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Republic of Lebanon

Electricity Sector Public Expenditure Review

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Sustainable Development Department

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Abbreviations and Measures

(Exchange Rate Effective November 8, 2007)

Currency Unit	**-**	**Lebanese Pound**
US$ 1	=	LL1,512

ABBREVIATIONS AND ACRONYMS

BOT	Build Operate Transfer
bps	Basis Points
CMM	Customer Metering Management CHECK
CRA	Charles River Associates
DBO	Design, Build Operate
ECA	Energy Conversion Agreement
EDF	Electricité de France
EdL	Electricité du Liban
GDP	Gross Domestic Product
GOL	Government of Lebanon
HCP	Higher Council for Privatization
IFC	International Finance Corporation
IFI	International Financing Institution
IPP	Independent Power Producer
ISN	Interim Strategy Note
L/C	Letter of Credit
LIBOR	London Inter Bank Offered Rate
LNG	Liquefied Natural Gas
MOEW	Ministry of Energy and Water
O&M	Operation and Management
PPA	Power Purchase Agreement
PIP	Public Investment Program
RIDPL	Reform Implementation Development Policy Loan
VAT	Value Added Tax

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Preface

Reliable and reasonably priced electricity is a main driver for growth, employment and competitiveness around the world. Indeed, development and cost efficient investment in energy systems has a proven correlation to GDP growth. When electricity supply experiences frequent interruption or is prohibitively expensive, economic growth tends to slow down, stagnate or even contract.

Lebanon has several engines for growth and growth has been strong since the beginning of the millennium. However several events such as the assassination of former Prime Minister Rafiq Hariri in 2005, the hostilities with Israel in 2006, and the fighting in the Palestinian camps, notably Nahr El-Bared, in 2007 have caused serious economic and political turmoil in Lebanon. The outlook for growth was therefore conservative for 2007 at 1%. However, several reform measures are being implemented and, if successful, are forecast to see growth back at around 5% within a few years.

One such reform is that of the electricity sector. The state of the sector has reached a critical stage, with a massive drain on public resources (estimated at 4% of GDP for 2007), huge revenue loss for industry and commerce, and exorbitant spending on back-up generation by the general population. The Government of Lebanon has made reform of the sector a major priority. The objective of this Public Expenditure Review is therefore to assist the Government in identifying measures that could improve service delivery, reduce the cost of the sector and increasingly introduce private sector participation to the sector to enhance efficiency, improve governance and ultimately meet the significant investment needs in the sector in the medium term.

It is important to note that this report is one of several diagnostic and advisory documents in use and under preparation in Lebanon. The backbone of the sectoral reform program is the comprehensive Paris III reform program. In addition, a Master Plan is under preparation with a draft envisaged in early 2008. Throughout the PER, it is suggested that the Master Plan analyses proposed options and suggestions in more detail and evaluates carefully their merit in the context of the overall least cost sectoral planning that goes into the formulation of a Master Plan. The Government has also contracted with the International Finance Corporation (IFC) to solicit private sector participation (PSP) to finance and operate new (and possibly purchase stakes in existing) generation assets. This PER does by no means replace the important due diligence work (e.g., market testing) that goes along with the work the IFC has been requested to undertake. The PER report focuses on analyzing the public expenditure impacts of PSP in the power sector in the context of the sector's current performance, status of overall sector reforms, and the Government's fiscal exposure. Finally, this PER focuses on conventional power production, and has not reviewed in detail the potential of solar, wind and further development of hydro energy in Lebanon given the prominence of the fossil fuel power plant production in Lebanon, and its impact on public spending. The World Bank does however encourage the Government's intention to diversify by reviewing the potential of non-conventional power generation sources.

Executive Summary

Introduction

1. The Lebanese electricity sector is at the heart of a deep crisis. The sector is unable to supply the reliable electricity needed by homes, offices and industry. It is a massive drain on government finances, crowding out more valuable expenditures on education, infrastructure, social protection, and health, and putting macroeconomic stability at risk. The sector accumulates huge debt with little to show for it, and those who are least able to provide for themselves suffer the consequences most. The state of the electricity sector symbolizes to the public Lebanon's profound challenges of governance, inclusion and accountability.

2. Power outages are a daily occurrence in Lebanon and in some regions of the country the quality of electricity supply is particularly poor. No new power generation capacity has been added since the two combined cycle plants were installed in the 1990s. This has led to a massive investment by consumers and industry in back-up arrangements. Indeed, this form of energy security is estimated to cost the population at least an additional 25% in spending on electricity per month[1]. The interruption in supply by the utility, EdL, is furthermore estimated to cost industry close to US$400 million in sales losses. This report includes detailed calculations on these estimated high costs to the public. This additional spending and revenue loss has an obvious negative impact on these consumer categories, but also makes implementation of other macro-critical, non-electricity sector reforms, difficult; as consumers have difficulty absorbing increased overall spending (for example tax increases).

3. Even worse, the poor electricity service provided by public sector is costing the Government massive amounts in the form of generalized subsidies. Some subsidization of the sector may be warranted if at least the service was reliable and there was an underlying sound strategy justifying the subsidies (e.g., targeted assistance to the poor). In Lebanon today, however, the subsidies are required to cover insufficient revenue due to a tariff set far below cost recovery (as well as an inefficient tariff structure), and low billings and collections. In addition, the continued use of gas-oil (diesel) in two major power plants (as well as in the gas turbines designed as peaking plants but used as base-load plants due to insufficient capacity to serve demand) designed to use natural gas (despite the abundance of natural gas in the region), high O&M cost of all power plants due to insufficient regular maintenance and spare parts, as well as high technical losses, result in very high production costs. Subsidies are estimated to have reached 4% of GDP in 2007[2], and 39% of total government spending between 1997 and 2006[3].

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[1] Based on a calculation of the average cost for back up generation as a percentage of total spending (EdL and back-up) on electricity in 2007. This is reported to be even higher in early 2008 due to an increase in outages.

[2] The subsidy figure is inclusive of debt-service

4. Besides the need for massive subsidies to EdL for an unreliable electricity service, there is a very real concern that Lebanon could reach the point of widespread and continuous blackouts as investment falls far behind demand.

5. Lebanon does not face any significant technical impediments to turnaround the performance of its electricity sector, but will have to make important decisions and trade-offs in order to achieve results. A major issue will be the sequencing of reforms and the pace of achieveable results. With the huge increases in the international oil price in recent years, the lack of tariff adjustment since 1996 (when the oil price as US$21/barrel) has become a clear and present problem and one that is closely linked to being able to address the fiscal drain of the sector. Having said that, with current service reliability problems, introducing up-front tariff increases will be very difficult and will be politically very charged. But there is a cost to delaying an adjustment as well: waiting with tariff increases will result in continued insufficient revenue to cover costs, and adjusting the tariff up-front before service reliability and consumer confidence has been restored may result in increased fiscal burden due to deterioration in the collection of billings.

6. As such, this report presents an analysis of possible demand and supply scenarios for the future, and lays out options for the Government to consider in improving service and reducing the overall costs. Each option is presented with a savings potential, and proposed time-line for implementation. Ultimately, however, the Government will have to consider how to sequence the reforms, in particular, the invariable tension between waiting with the much needed tariff level and structure adjustments for an observable improvement in service delivery versus starting the adjustments immediately and working on service improvements in parallel. Each course of actions has a "cost".

Reforms Options and the Impact on Public Expenditures

7. This report estimates that the demand for electricity in Lebanon is likely to increase by 60% by 2015 to 20,598,450 MWh. This implies an increase of at least 1,500 MW of power generation capacity (assuming currently installed capacity is maintained). This in turn will require capital investments of at least US$1 billion. This is a base case assumption, and this report also estimates possible lower and higher demand growth based on varies GDP growth scenarios. The assumption is that self-generation will continue to constitute about one third of overall electricity consumption over the foreseeable future. This is despite the implementation of reforms and a restructuring of EdL since maintaining the 67% share of electricity consumption met by EdL each year is considered challenging enough.

8. Lebanon has several options for new generation capacity. This report recommends that new generation capacity is implemented in parallel to three other key supply enhancing undertakings which each would contribute towards making more capacity available while having positive returns to the sector. These are:

[3] Quoted from Byblos Bank: "Lebanon This Week", Issue 40, October 22, 2007.

- Improving dispatch to of generation capacity to meet demand at least cost through the urgent completion of the National Control Center. **This could save an estimated US$24 million in fuel costs per year**.

- Reducing technical losses to free-up generated electricity to meet demand (and bill for it). **A reduction in technical losses from the current 15% to 10% would free up about 100 MW of capacity, avoiding investment in the equivalent amount (a saving of about US$80-US$100 million in avoided investment cost) and enabling this amount of already generated electricity to be billed to consumers rather than being lost in the network**. The benefit in terms of payback period for the investments required for this (estimated at US$200 million) is not quick (partly due to the fact that the benefits have been calculated based on the current tariff and regular maintenance of the network has been neglected for a long time hence resulting in large investment needs). Reducing these losses is however deemed as necessary to enable overall reforms in the sector (sends positive signals) and is closely linked to tackling the theft of electricity. In other words, this report considers that achieving technical losses better aligned with international best practice (8%-10% for some of the world's best performing electricity utilities) is a necessity to improve the technical, financial and governance performance of the sector.

- Rehabilitation of the two existing large steam-cycle power plants, Jieh and Zouk to extend their operational lifetime by 10 years. This report estimates that these two power plants (almost 50% of Lebanon's current supply) could operate for another 10 years if rehabilitated and then maintained properly**. This can be done within a 2-3 year period, will cost about US$100 million per plant (possibly less) and yield rates of return of 20% (Jieh) and 27% (Zouk) and annual savings of US$60 million due to fuel use which is closer to the designed values for fuel use in gram/kWh terms.**

9. As far as adding new generation capacity is concerned, Lebanon has several options in terms of technologies, but the decision will and should be driven by a comprehensive fuel supply strategy, which takes into account both least cost considerations, environmental considerations as well as energy security. The table below shows the most obvious technologies and fuels possible:

Generation technologies and fuel options

	Piped Gas	**LNG**	**HFO**	**Diesel**	**Coal**
CCGT	Yes	Yes	No	Yes	No
Steam Cycle	Yes	Yes	Yes	No	Yes

10. The analysis undertaken in this report shows that, assuming that the new plant will operate with a load factor of 85% (i.e. as a base-load plant) and before accounting for energy security considerations, piped natural gas is the cheapest option, followed by coal.

The least economical fuels for Lebanon are gas-oil (as currently used at Beddawi and Zahrani) and LNG, although both could prove attractive for energy security reasons**.**

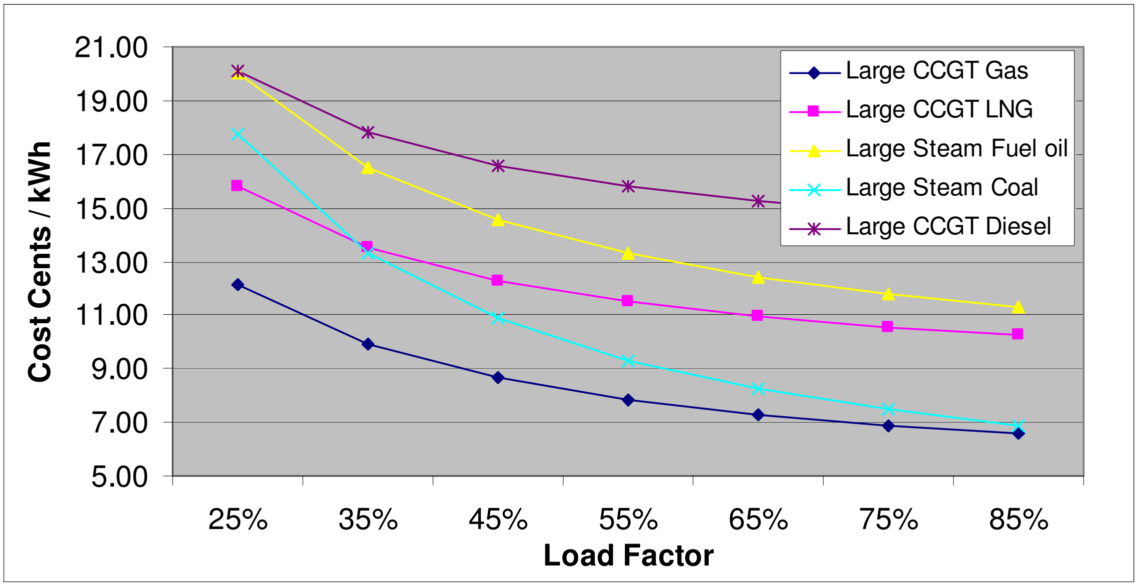
11. It is important to note that this assessment is for a new generation power plant assumed to be sited in such a way that it can access piped natural gas. For Zahrani, LNG remains a more economically attractive option than the gas-oil currently used. A careful feasibility study needs to examine whether LNG compares favorably to piped natural gas transported on a domestic pipeline, taking into account the availability of piped natural gas, the cost of pipeline construction and the environmental aspects of such construction.

12. **It is recommended that the Master Plan underway carefully reviews technology and fuel options for Lebanon, including coal and LNG as well as ideal locations of new plants for fuel procurement and security. It is furthermore recommended that Lebanon considers switching Zahrani to LNG provided competitive bids for LNG supply can be obtained since it is still significantly cheaper than gas-oil (an estimated 8.92 US¢/kWh compared to 14.68 US¢/kWh).** If sufficient Egyptian gas can be secured through the Arab Gas Pipeline, the concept of a domestic natural gas pipeline should also be considered, which would have even greater savings than LNG (7.22 US¢/kWh)[4]. Zahrani's technically viable fuel options are natural gas (piped or LNG) or gas-oil since it is a CCGT.

13. A pipeline should be constructed if gas is available in sufficient quantities (this would be initially from Egypt, and later could come from other sources in the region such as Iraq, the Gulf or Caspian countries), and if transit risks can be effectively mitigated.

[4] The calculations in paragraph 12 are based on annual generation of 3,300 GWh per annum (p.a.), diesel fuel consumption of 650,000 tons p.a., gas consumption of 21,600 bbtu and a pipeline investment cost of US$200 million. The assumed LNG facility costs are presented in this report (chapters 3, 4).

A comparative of technologies and their fuel price assumption for new power plant construction in Lebanon



Fuel Cost Forecast		2006	2007	2008	2009	2010	2011	2012	2013*	2014*	2015*
Crude Oil Price (IEA forecast) (i)	US$/barrel		71.3	88.5	83.0	81.0	80.5	80.3	77.0	75.1	73.2
Crude Oil Price for Lebanon (ii)	US$/barrel		73.4	91.2	85.5	83.4	82.9	82.7	79.3	77.3	75.3
Diesel (iii)	US$/ton		667.4	828.4	776.9	758.2	753.5	751.1	720.3	702.5	684.7
HFO 1% (iii)	US$/barrel		343.0	425.7	399.2	389.6	387.2	386.0	370.1	361.0	351.9
Australian Coal (iv)	US$/metric ton	49.1	58.1	66.1	63.6	62.6	62.4	62.3	60.7	59.8	58.9

(i) Latest IEA projections, as used by the IMF
* logical suite calculated from the past 5 years)
(ii) 3% mark up to reflect Lebanon's situation
(iii) using similar assumptions of conversions than previous versions (based on crude oil prices), with updated ratios based on historical 2007 DEC fuel prices (leading to the same ratios as when using IEA historical)
(iv) using 2006 price, indexed at 50% to crude oil prices (using an average 47% price ratio, calculated from historical 2003-2007 crude oil and coal prices)

14. The prices for piped gas and LNG have been assumed to be constant at US$5.65/mmbtu and US$11/mmbtu, respectively. The rationale for this is that for piped natural gas there is a long-term agreement in place with Egypt. The price reference for LNG is based on recent similar projects world-wide.

15. Another important issue to consider in the context of new capacity investment is the participation of the private sector. The private sector is already active in Lebanon in the management and operation of several aspects of the power sector, from O&M contracts on major power plants to concessions in the distribution of electricity, to billing and collection. So far, however, the private sector has not assumed any capital risk.

16. Financing of the sector is obviously going to be viewed as much riskier by the private sector than is management because of the large deficit in the sector. This report analyses that private capital will be reflected in the increased incremental cost per kWh produced at a level of about US¢1.60/kWh assuming the power plant operates as a base-load plant (i.e., at 85% load factor). In other words, each kWh produced under an IPP scheme would cost US¢1.60/kWh more than under a public financing scheme. This analysis does not account for any efficiency gains that could be derived from the private sector's assumption of risk (although efficiency gains could be achieved by outsourcing the construction and operation of a new plant to the private sector without necessarily the

financing). Payments against the price charged by the IPP developer would have to be (largely or entirely) guaranteed by the Government, and/or paid directly through tariff increases or subsidies.

17. This report does not discourage the undertaking of IPPs, nor does it advocate for public financing of new generation assets. What it does do is **recommend that the Government carefully evaluates the benefits and costs of private vs. public financing, and consider all options, including a private management scheme (e.g. design, build, operate, DBO) and makes an informed decision. The report also recommends against the management or implementation of generation projects by the public sector**. **The report also strongly recommends that the Government establishes a transparent fiscal accounting framework for any contractual obligations for power purchase or investment so that it can monitor its exposure**[5]. Indeed, this report sees the private sector as part of the solution but it is not a panacea and should not be a substitute for the long-delayed power sector reform. The private sector without power sector reform will be expensive for the Lebanese tax-payer.

Reform Measures to Contain the Public Drain

18. The Government announced a comprehensive reform program for the power sector at the Paris III conference in January, 2007. This program has enjoyed a broad consensus since it is based firmly on the 2002 Electricity Law and was designed by the pre-November 2006 coalition government (whose Minister of Energy and Water at the time was from Hizbollah), and approved by Cabinet in July 2006 just before the outbreak of hostilities with Israel.

19. This is an important milestone in the reform effort in Lebanon since many previous reform programs have stalled due to lack of consensus and agreement. At present and despite risks that implementation of some reforms may not be sustained, progress is being made even under the challenging political situation prevailing in Lebanon today.[6].

20. The reform measures included under the Government's reform program will bring substantial savings to the sector. They comprise cost reduction through fuel switching and loss reduction, and revenue enhancement through better billing. In addition, EdL will be restructured, and ultimately privatized to improve efficiency and governance – given the current high level of political interference in the sector.

21. This report has identified a set of additional reforms as well as quantified some measures under consideration by the Government (i.e., fuel conversion at Zahrani).

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[5] In this context, it is worth noting that in some countries fiscal accounting is insufficiently transparent to capture government guarantees and other contingent liabilities derived from private infrastructure investments. In those cases, the benefits of private participation can be overestimated, and the attendant fiscal risks underestimated – until a generalized macroeconomic or currency crisis hits.

[6] The reforms are supported by the Emergency Power Sector Reform Capacity Reinforcement Project, approved March 2007, and the Reform Implementation Development Policy Loan, August, 2007 (World Bank).

22. All of the reform measures (Paris III and the additional reforms recommended by this report) are presented in the table below, along with their savings potential between now and 2015. Some measures can have immediate impact and should be pursued immediately; other measures need some time to yield returns but should also be pursued immediately. **Of highest priority is fuel switching at Bedawwi and Zahrani, which would comprise on average 50% of the total subsidy savings up until the period 2015**.

Electricity sector reform measures to improve service reliability and reduce subsidies

	SAVINGS (US$ Million)											
REFORM MEASURES	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	Short-term (less than 1 year for net benefits to be realized)	Requires capital investment	Capital investment under implementation
Paris III Reforms												
Improvement in billing through reduction in non-technical losses from 17.8% to 8% by 2012	0.0	7.3	23.0	48.7	68.8	81.9	86.8	91.9	97.3	yes	some	under tendering (CRA)
Conversion of Beddawi to piped natural gas as of July 1, 2008	0.0	208.2	382.9	370.8	367.7	366.2	346.1	334.6	323.0	yes	minor	no, but not major
Optimization of T&D network to reduce technical losses from 15% to 10% by 2012	0.0	14.8	29.2	45.3	63.6	83.9	85.2	88.0	90.9	yes	yes	partially, NCC
SUB-TOTAL	**0.0**	**230.3**	**435.1**	**464.8**	**500.1**	**532.0**	**518.1**	**514.5**	**511.2**			
Operating subsidy as a % of GDP before debt service	**3.5%**	**3.6%**	**2.5%**	**2.3%**	**2.2%**	**2.1%**	**2.0%**	**1.9%**	**1.9%**			
Additional Recommended Measures by the World Bank												
Revision of heavy fuel oil specifications from 1% to 3.5% sulfur	0.0	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	yes	no	n/a
Rehabilitation of Jieh and Zouk power plants	0.0	0.0	0.0	59.8	59.5	59.4	57.5	56.5	55.4	no	yes	no
Private operation of Jieh, Ziuk, Baalbeck and Tyre	0.0	-8.0	19.7	19.0	18.8	18.8	17.7	17.0	16.4	yes	management fee	n/a
Revision of terms to concessions	0.0	19.5	30.8	32.6	34.5	36.5	38.7	40.9	43.4	yes	no	n/a
Improved fuel chain surveillance	0.0	72.0*	72.1	74.6	78.5	82.9	84.2	87.0	89.9	yes	surveillance fee	n/a
Zahrani conversion to LNG	0.0	0.0	0.0	198.4	195.3	193.8	173.7	162.2	150.6	no	yes	no
SUB-TOTAL	**0.0**	**23.2**	**134.3**	**396.1**	**398.3**	**403.1**	**383.5**	**375.3**	**367.4**			
GRAND-TOTAL	**0.0**	**253.5**	**569.4**	**860.9**	**898.4**	**935.1**	**901.6**	**889.8**	**878.6**			
Operating subsidy as a % of GDP before debt service	**3.5%**	**3.2%**	**2.0%**	**0.9%**	**0.9%**	**0.8%**	**0.8%**	**0.9%**	**0.9%**			

Notes:
All saving estimates are net of required investments
* net of surveillance cost

23. As is illustrated in the table above, implementation of all of the reforms could see the subsidies reduced to less than 1% by 2010.

24. However, as is also illustrated, the subsidies cannot be eliminated completely under these measures, and under the assumptions underpinning the analysis. The most sensitive variable is of course the oil price assumption, which is based on IEA's forecast. Should oil prices drop dramatically, the subsidies would naturally also be reduced. Should they prevail, on the other hand, subsidies, albeit reduced, will continue to the sector.

25. This highlights the importance of including an action plan for restructuring the electricity tariffs as part of the sector reform. This is particularly important in light of the fact that the tariff has not been adjusted since 1996 when the oil price/barrel was around US$21. According to EdL the tariff is set to cover an oil price of about US$25/barrel.

26. The structure of the tariff also needs to be revised to reduce the generous block tariff which subsidizes consumers who could pay a higher tariff. Increasing the tariff will no doubt be commercially and politically challenging given the current poor service and need to pay for back-up arrangements, and would need to be phased in progressively and accompanied by more effectively targeted social protection.

27. The tariff increase required under various scenarios has been estimated in this report. The analysis finds that full cost-recovery could be achieved through either a one-off increase in the average tariff of 99.2% or a gradual increase over three years of 26.5% for the first two years and 24.5% in the third year). Formulation of a tariff adjustment action plan is included under the Bank supported Emergency Power Sector Reform Capacity Reinforcement Project and **it is recommended that a tariff adjustment action plan be made a priority deliverable under the consulting assignment funded by the above-mentioned project and that this action plan endorsed by the Government for implementation, along with the development of adequate social protection measures, to mitigate adverse impact on vulnerable consumers**.

28. The Paris III Reform Program commits the Government to putting in place a targeted cash assistance system but further work is necessary on the design of mechanisms to deliver the cash assistance program. The World Bank is assisting the Government in this design through the Emergency Social Protection Implementation Support Project (ESPISP) as well as the forthcoming Poverty and Social Impact Assessment focused on the electricity and water utility services. Without such well designed and targeted social protection, the best intended tariff adjustment plans often remain just that – plans.

Chapter 1: Public spending, governance and electricity in Lebanon

Lebanon's public finance crisis is and has been for a long period closely linked to a very poorly performing electricity sector. The sector costs massive government resources and, on top of it, consumers pay massive additional amounts for energy security. Addressing the problems, which from a technical point of view are not unique to Lebanon, has proven challenging due to lack of agreement on reforms, their benefits and elimination of the status quo. The benefits of reform through a series of cost reduction and revenue enhancing measures can have a major impact on reduced subsidy requirements to the sector. However, unless EdL is restructured and political support and will continues to be behind the restructuring in a way that eliminates political interference, the subsidy-reducing measures are unlikely to be implemented and EdL will remain a massive drain on public resources and a symbol of Lebanon's profound challenges of governance, inclusion and accountability.

Introduction

1.1 Lebanon suffers from a severe public finance crisis. Public debt (about US$40 billion) reached 185% of GDP in 2006; ranking among the highest in the world. However, a liquid domestic banking sector and interest by the international capital markets has enabled the Government of Lebanon to continue to issue bonds to meet debt obligations. While this strategy has allowed the Government to avoid defaulting on debt repayment obligations, it has increased debt to unsustainable levels. Fiscal adjustment and structural reforms to induce growth and reduce public expenditure are prerequisites for sustainable debt reduction in Lebanon. A key contributor to the public finance crisis is the continued drain on resources by the power sector which is estimated to cost Lebanon 4% of GDP in 2007.

1.2 The Government presented a comprehensive reform program at the International Donor Conference held in Paris (Paris III) on January 25, 2007. The main objectives of the Government's reform program are to stimulate growth, create employment and reduce poverty, with a significant emphasis on the energy and social sectors as engines for this, as well as for curbing public spending. Significant effort is being made to implement the reforms, despite the current political crisis.

1.3 Key pillars of the program are: (i) fiscal adjustment to reverse Lebanon's presently unfavorable debt dynamics and reduce the debt-to-GDP ratio through rationalization of expenditures, enhancement of revenues, and improved efficiency; among the key measures are energy sector reform and privatization (focusing on selected telecommunications assets and licenses in the initial phase); (ii) growth-enhancing structural reforms to strengthen the business environment and the competitiveness of Lebanon's businesses; and (iii) social sector reform to strengthen social safety nets to reduce poverty and vulnerability and increase efficiency and effectiveness of social spending including in health and education[7]. The structural reforms envisaged in the power sector are critical for both improved fiscal/debt sustainability and growth prospects in the medium-to-long term. Energy sector reforms center around administrative

[7] Adequate social protection will be essential to successfully implement the Government's reform program, including power sector reforms.

reform of the state-owned enterprise EdL and undertaking of high priority investments (through as much private sector participation as possible) to improve services and reduce costs (including through conversion of the production system from oil to natural gas, upgrading and rehabilitation of the transmission and distribution network, and reducing non-payment). Box 1.1 summarizes the power sector reforms envisaged by the Government.

Table 1: The Power Reform Program

Enabling initiatives:

- Appoint qualified advisors to the Ministry of Energy and Water, EdL and HCP
- Compete the auditing of EdL's 2001-2006 financial statements
- Appoint a new Board of Directors for EdL
- Establish the Electricity Regulatory Authority and design its bylaws
- Introduce potentially necessary amendments to the Electricity Law 462
- Corporatize EdL
- Design establishment decree and new bylaws for EdL
- Unbundle EDL's generation, transmission, and distribution functions
- Complete the establishment of a National Control Center

Short-term restructuring initiatives:

- Modify restrictive oil specifications based on 2003 study
- Negotiate additional bilateral contracts for fuel oil and gas oil to reduce high premiums
- License private companies to install and operate remove meters
- Reduce illegal network connections and enforce bill collection
- Secure the supply of LNG to the Zahrani power plant

Medium term restructuring initiatives:

- Secure the supply of natural gas to the Deir Ammar (Baddawi) power plant
- Build a gas pipeline between the Zahrani and Baddawi power plants
- Complete the extension and rehabilitation of the 22 KV transmission network
- Complete the infrastructure needed for the Ksara Stations to allow Lebanon's integration into the regional electrical network ("Seventh Joint")
- Decide on the future of the Zouk and Jieh power plants
- Privatize EdL

Other potential improvements include:

- Rehabilitate existing plants, particularly Zouk and Jieh
- Install additional capacity in Baddawi and Zahrabi (with private sector participation)
- Sign contracts with private companies to produce electricity and sell to EdL
- Increase hydro-electrical production capacity (BOT contracts)
- Provide the necessary investments to improve transmission and distribution
- Secure more financing to invest in additional capacity to meet increased energy demand by 2015

Source: Government of Lebanon Document to Paris III

Governance and the electricity sector

1.4 During the 1975-1990 war, provision of public services and utilities suffered substantially. Government revenues, as well as utility revenues, were reported to be depleted by militias. Public abuse of electric power was common before the war, but became very widespread during the war.

1.5 The power sector has never recovered from the reduction in output and in the billing and collection of electricity that intensified during the war. Supply continues to be insufficient of demand, back-up generation is as a result widespread throughout Lebanon, and over 30%[8] of produced electricity is not billed. The industrial sector no longer can afford to rely on public provision of electricity[9].

1.6 The lack of revenue generation in the sector over many years has resulted in insufficient operation and maintenance of system assets, which in turn has increased the cost of power generation substantially. The widening gap between power supply and demand, the frequent outages and the significant spending on alternatives by all Lebanese has made increasing the electricity tariff challenging. With today's very high cost of oil (Lebanon imports all fossil fuels), the current tariff only covers a small portion of operating costs and massive Government subsidies are required.

1.7 Fixing the power sector has been on the agenda of several governments in Lebanon, yet as of today there are only limited achievements. Reliable electricity continues to be a major impediment to growth and competitiveness, EdL continues to cost the public massive resources, and consumers continue to have to pay for two sources of electricity in order to have one secured. So what is the problem?

1.8 The problems of the power sector are not unique to Lebanon. Lack of capacity, lack of O&M spending, insufficient tariffs, back-up generation – these are characteristics of many developing countries' power sectors. The issue in Lebanon that is exceptional is the difficulty in agreeing *how* to improve the sector, ranging from the degree of private sector involvement to sector structure, and to embark on initial steps.

1.9 A key source of resistance to change has been the lack of common objectives among major stakeholders in restructuring the sector. A poorly- performing electricity sector in a middle-income country tends to go beyond technical issues. Indeed, it can often be traced back to a situation where there are multiple beneficiaries of the dysfunctional status quo in the sector, ranging from corruption in payments flows or procurement, to buying of voters through free electricity, to profiteering from energy shortages. In Lebanon, there are several technical aspects that have a root problem in poor governance ranging from the procurement of CCGT in the absence of natural gas, the use of 1% sulfur content fuel which only has one market instead of 3.5% sulfur content which can procured competitively and the inordinately generous distribution margin in the distribution concessions to name a few. Overcoming such vested interests, and

[8] This reflects the 17.8% illegal consumption as reported by EdL. In addition, technical losses in the network amount to 15% according to EdL.
[9] Based on discussion with the Chamber of Commerce and the Industrialist Association.

serving the national interest, can of course be challenging in countries where political consensus is difficult to reach.

1.10 In Lebanon, an agreement was finally reached after many years on how to restructure the sector: the Electricity Law (Law 462 of 2002) sets out the general path for restructuring EdL, and the Cabinet approved key implementing steps in July 2006. The reforms of the sector proposed as part of Paris III build on Law 462 and the July 2006 decision and appear to be based on broad consensus. At this critical point where Lebanon needs the power sector to enable growth rather than hamper it and with high oil prices likely to continue, the power reform program needs to be given the highest priority. The move to create an inter-ministerial committee for infrastructure including power and chaired by the Prime Minister was an important step in the right direction. However, the reform needs to be championed on a day-to-day basis by a dedicated team in the Government – at the highest level – and with political support and will for it to succeed. And any beneficiaries of the status quo will need to forego their gains in return for Lebanon's gain.

Chapter 2: Demand for electricity and consumer spending on electricity

Despite an electrification rate of close to 100%, Lebanese electricity consumers suffer from frequent power failure and substantial spending on back-up generation for as much as one third of their electricity consumption. This is estimated to cost the average residential consumer an additional 25% on top of what they pay EdL every month; and the industry sector about US$360 million in lost sales per year[10]*. Demand for electricity is likely to reach over 4,000 MW by 2015 which would require an additional 1,500 MW of new capacity. Unless EdL improves its ability to supply electricity and install new capacity and restore consumer confidence, back-up generation will increase its share of electricity supply in Lebanon from 33% at present to close to 60% by 2015.*

I. PAST DEMAND OF ELECTRICITY

Introduction

2.1 Self-generation plays a large role in electricity supply and demand in Lebanon, despite the high level of electrification (99.9%).[11] The use of back-up supply is particularly prominent in the industrial sector as well as among low-voltage consumers (households and commerce). The reason for this is the inability of EdL to meet demand effectively due to insufficient generation capacity, high levels of lost electricity (i.e., electricity that never reaches the consumer) and poor load management. Since the demand met by EdL is constrained by its generation, transmission and distribution capacity, it does not represent the full demand for electricity in Lebanon. Unfortunately, statistics available within Lebanon for electricity demand only cover the electricity distributed by EdL. Self-generation and un-served demand are not recorded systematically. In a background report to the Hydrocarbon Strategy Study, prepared by the World Bank in 2004, Chubu Electric analyzed the demand for electricity in Lebanon and estimated that about 33% of total electricity demand was met through self-generation. The recent household study puts the number at 38%. 33% has been retained for this version of the draft report, but could be updated based on agreement with counterparts in Lebanon.

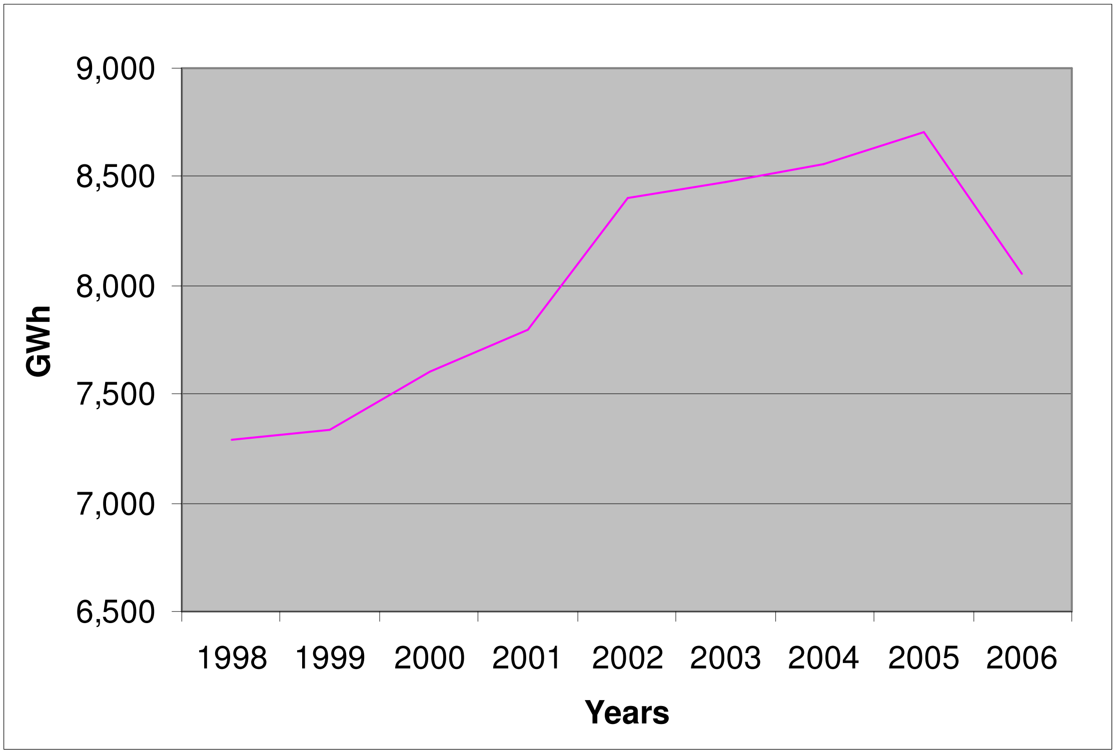
Past Demand Met by EdL

2.2 Electricity demand met by EdL grew from 7,300 GWh in 1998 to 8,056 GWh in 2006 according to data collected from EdL. This represents an average increase of 1.2% per annum (p.a.) over that period, during which the increase was stronger between 1998 and 2002 at 3.6% p.a. and actually decreased by 1.7% p.a. between 2002 and 2006 (see Graph 2.1 below). The decrease in demand met by EdL in 2006 is partially explained by destruction to the electricity

[10] Please see further in this chapter the assumptions behind these estimates.
[11] World Energy Outlook, IEA 2006.

infrastructure caused by the hostilities with Israel in July-August 2006. However, the pattern demand met by EdL otherwise suggests that EdL is increasingly unable to satisfy the country's overall demand for electricity, and, as a consequence, the share of electricity demand met through self-generation increased over the period.

Graph 2.1: Historical demand met (i.e., electricity supply by EdL) 1998-2006 in GWh



Source: EdL statistics department, 2007

2.3 During the same period (1998-2006), average GDP growth was 2.6%, with particularly strong growth in 2003 and 2004 (see Table 2.1 below). In middle income countries - such as Lebanon – there tends to be a correlation between GDP growth and electricity demand growth which is greater than 1, meaning that demand for electricity grows at a factor above the GDP growth. This supports the conclusion (and the Chubu report as well as Household Survey) that that the actual demand for electricity in Lebanon is significantly higher than what EdL is capable of supplying. Lack of sufficient capacity by EdL to meet demand further undermines the already weak consumer confidence in the public provision of electricity supply which in turn makes the already difficult reforms of the sector even more difficult to implement.

Table 2.1: Increase in met demand by EdL and real GDP growth between 1998 and 2006

	1999	2000	2001	2002	2003	2004	2005	2006
Increase in demand met by EdL[12]	0.6%	3.7%	2.5%	7.7%	1.0%	0.9%	1.7%	-7.4%
Real GDP growth[13]	-1.1	1.5	4.7	3.1	4.1	7.4	1*	0*

Source: World Bank Interim Strategy Note, July 2007; * Estimates as of June 2007.

[12] Based on data provided by EdL.
[13] Source: World Bank Interim Strategy Note for Lebanon, July 9, 2007.

Self-Generation

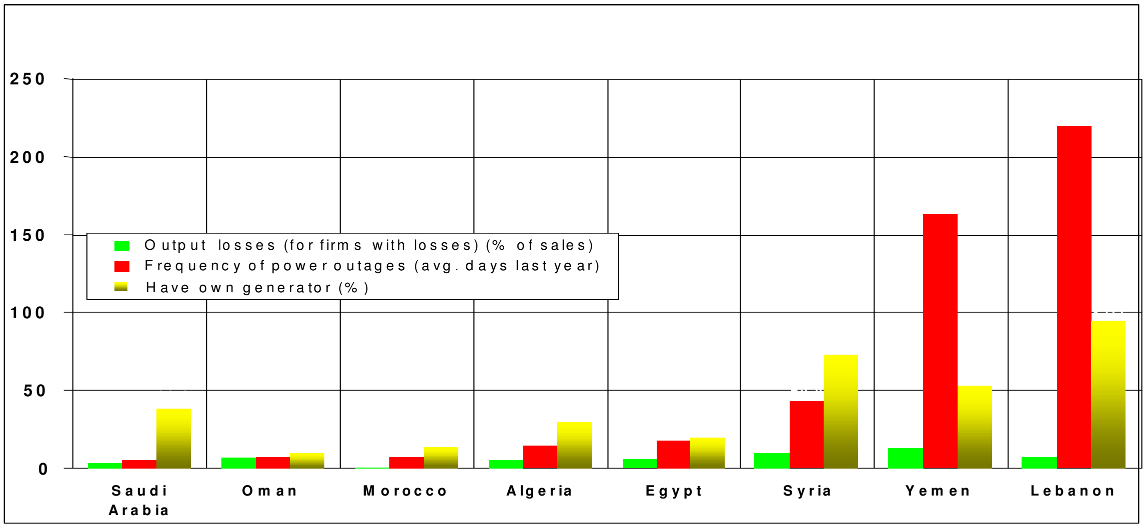
2.4 As mentioned above, the use of back-up and self-generation play a very important role for many Lebanese to satisfy their need for electricity. Most commonly, individual or community-based back-up generators are used, kicking-in when EdL's supply is unable to meet demand; or, as in the case with large industries, when industries find it more economical to generate their own electricity due to the tariff charged by EdL as well as the risk (and cost) of interrupted supply. This happens during peak periods when the tariff charged to industries on the medium voltage network is three times the tariff charged during off-peak periods (see Annex I). In essence, most consumers retain a connection both to EdL and to an alternative supply point. Graph 2.2 compares the impact of power failures on industries in Lebanon and other countries in the region.

2.5 In addition to the estimates provided in the 2004 Hydrocarbon Strategy Study[14], the Investment Climate Assessment (ICA) prepared in 2006 also provides useful data on self-generation. According to the ICA, 100% of large and medium-size entrepreneurs surveyed declared they have their own generators[15]. For many industries, the tariff determines when they rely on EdL or their own generators to meet their needs as the peak tariff charged to industries is higher than the cost of self-generation using fuel-oil (see section above and on tariffs below).

2.6 According to the ICA, consumers incur 220 interruptions of service per year on average (133 interruptions in Beirut and 300 outside of Beirut[16]). Lebanon's performance in this respect is clearly the worst in the region. In spite of the substantial investments in private generation, firms, for example, cannot fully compensate for the failings of EdL and report substantial losses from power interruptions and voltage fluctuations. The average firm reports losing 7% of its sales value due to these interruptions. Larger firms are better able to compensate for power failures than small firms and report losing about 5% of sales. Small firms report losing as much as 8% while medium-sized firms about 6%. Firms located outside Beirut experience somewhat higher average sales losses (about 8%) than those within. According to the ICA, the industries most affected by power interruptions[17] are textile and clothing firms, which report losing 10.3% of sales, and hotels, which report losing 9% of sales. Assuming that affected industries[18] are mainly in the industrial sector, which represented 20.8% of GDP in 2004, and based on an estimated GDP of US$22 billion (2004 estimate), the economic loss to Lebanon may be as high as US$360 million per year.

[14] Lebanon Hydrocarbons Sector Strategy Study, January 2004, Annex 2
[15] Lebanon ICA June 2006, paragraph 66.
[16] ICA June 2006, page 26
[17] ICA June 2006, page 27
[18] The ICA estimate for the production lost because of poor reliability of electricity is 10.3% for clothing, 9% for hotels. As not all industries may be affected to that extent, a conservative average of 8% has been retained.

Graph 2.2: Comparative impact of power failures on Industries in Lebanon and in the MNA Region



Source: ICA study, 2006

2.7 The need for alternative supply arrangements is costly also for Lebanese household consumers. Residential users consuming from a community-based generator usually pay a flat monthly fee, regardless of their level of consumption. This fee is reported to range from US$20 to US$40/month[19]. In addition, these consumers pay for the electricity supplied by EdL, which, depending on family size and usage, can range from US$80 to US$200/month[20]. Consumers are therefore forced to pay up to an additional 25% for "security of supply".

2.8 In defining a policy toward self-generation, the Government needs to take into consideration the fact that the capacity of EdL's generation system is presently unable to serve Lebanon's total demand, and that the energy sector is facing considerable investment needs to maintain the existing system, as well as to meet future demand. It is therefore clear that in the medium term EdL will not be capable to capture the totality of the demand currently served through self-generation. Under these circumstances, a policy of cooperation and coordination with the large self-generators from the industrial sector[21] should be considered, including (i) clarifying the legal status of self-generators and back-up providers, in order to make their activity fully legal and to submit them to a minimum of regulation in the interest of the public, recognizing that they provide a service that EdL cannot supply in the medium term; and (ii) entering into formal agreements with some of them to the effect that they would provide stand-by back-up capacity to the EdL system and sell electricity to EdL during certain periods.

Estimated Total Past Demand

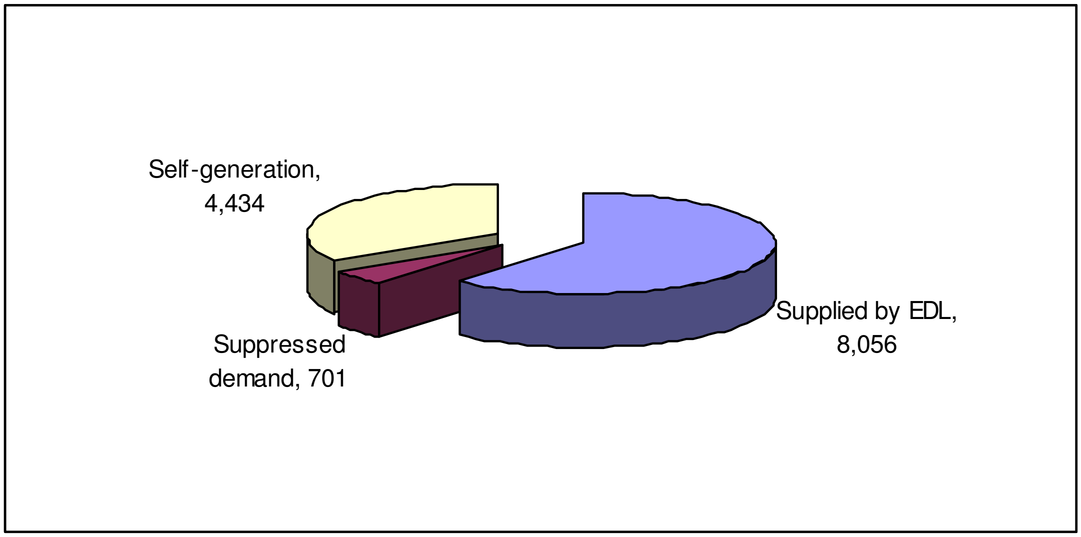
2.9 Based on the analysis prepared by Chubu in 2004, of the 33% self-generation, 67% of the demand met by self-generation was estimated to be for high voltage demand, and 11% for low

[19] Based on conversations with residential consumers in the Beirut area.
[20] Same as above.
[21] Large self-generators represent about 3.5 TWh according to the Chubu Consultant estimate, or between 400 and 500 MW of capacity.

voltage. In addition, Chubu estimated that un-served or suppressed demand represented approximately 8.8% of demand met by EdL.

2.10 On that basis, the electricity consumed in Lebanon can be estimated at 13,200 GWh in 2006, of which about 61% was supplied by EdL, 34% was supplied by self generation, and the rest represented suppressed demand (Graph 2.3). This assessment is based on a reported average load factor (i.e., the ratio of average energy demand/load to maximum demand/peak load) of about 60% in 2006. Broken down, the load factor was 40% for residential consumers and 50% for industries[22]. Peak demand reached 2,614 MW in 2006.

Graph 2.3: Estimated Total Demand of Electricity in 2006 (in GWh)

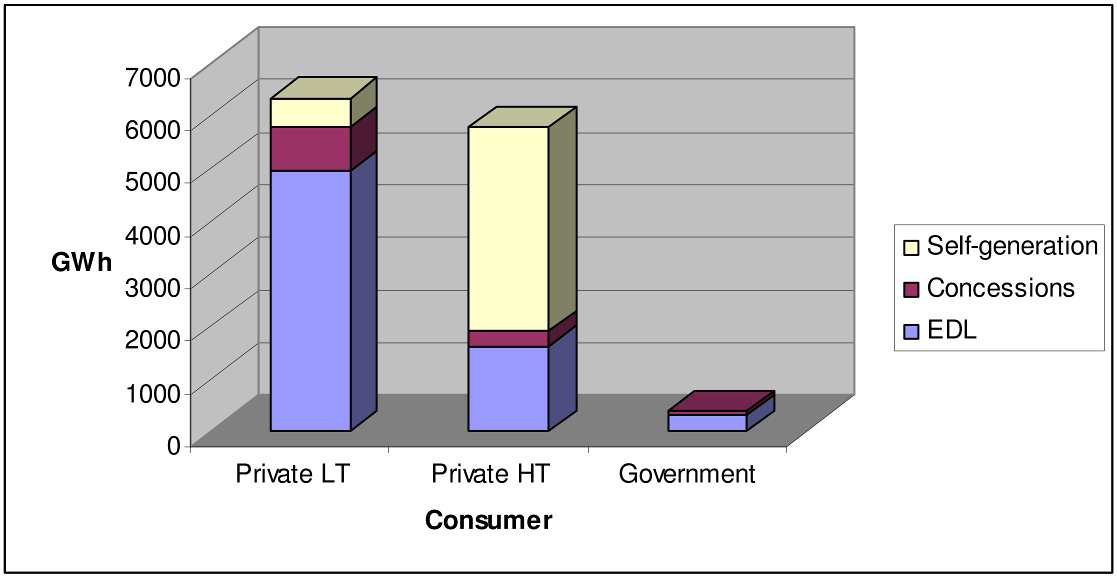


Source:World Bank Analysis, 2007 based on Chubu Consulting report data.

2.11 Of the electricity consumed, private low-voltage consumers represent more than half of the demand in Lebanon (see Graph 2.4 below). This high proportion reflects the importance of small service businesses in the country and is due to the aggregation in this category of both residential and small business consumption. EdL statistics do not allow for a more detailed breakdown between these two categories.

[22] The load factor is higher for the whole system than the average of load factor by category of consumer because of the time lag in the peak demand for each type of consumer.

Graph 2.4: Power consumption in Lebanon, by main user categories, 2006 (in GWh)



Source: EdL statistics, Chubu Consulting report and Bank mission estimate

II. ELECTRICITY SUPPLY

Losses in the Supply of Electricity

2.12 Chapter 3 provides an overview of how electricity is supplied in Lebanon today and presents supply options for the future. This section aims therefore at describing the basic characteristics of Lebanon's supply of electricity, in order to provide input to the forecast future demand for electricity.

2.13 EdL distributed about 8,056 GWh of electricity in 2006. Of the electricity supplied by EdL, a significant portion is lost either due to technical losses in the network or due to theft. Technical losses are reported to be in order of 15% in 2007[23]. Non-technical losses - which essentially comprise non-billed consumption of electricity (either through illegal connections or informal agreements in the distribution of electricity) – are reported to be about 18% in 2007. This 18% of non-billed electricity translates into US$150 million[24] in lost revenue for EdL and is partly explained by a weak billing system within EdL, but also by political interference in the operation of the utility.

2.14 Over the years, EdL has sought to reduce its non-technical losses, and a decline of about 3% was achieved during 2004-05. However, more drastic actions and results are needed, including: (i) a revision of the billing system and client registry; (ii) an internal reorganization of the commercial and billing functions in EdL with suitable incentives to staff and adequate resources; (iii) considering outsourcing of the billing, metering and collecting functions to

[23] Source: EdL.
[24] Based on estimated power thefts of 18% of the 2007 EdL supply of 8.8 TWh, amounting to 1.6 TWh evaluated at the average 2007 tariff of USCents 9.4/kWh (this includes the fixed and variable part of the tariff).

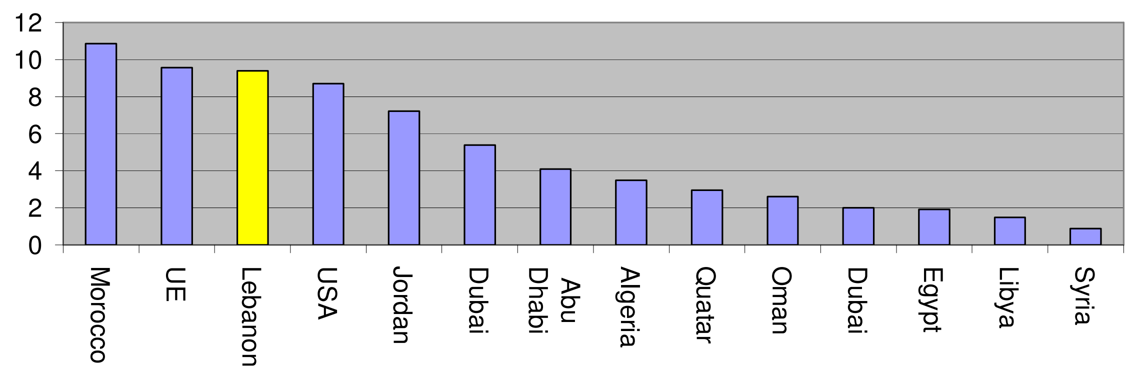
private operators[25]; (iv) continued enforcement and improvement of such; and (iv) considering the modernization of the metering and billing technology. Measures (iii) and (iv) are currently being tendered for (see Chapter 5) and involve large scale investments to update the metering. It is recommended that any outsourcing and any new metering technology be introduced gradually and tested in pilot areas before national roll-out takes place to ensure that the resources put towards these measures are economic and efficient.

III. ELECTRICITY TARIFFS

Tariff Level

2.15 Lebanon's electricity tariff level is high by regional standards and in relation to service quality, but too low to cover EdL's costs. The overall average tariff for 2006, based on billed energy, was LL141/kWh (9.4 US¢/kWh). Compared to electricity prices in the region, the Lebanese tariff level falls in the upper bracket. For the sake of comparison, the average tariffs in neighboring countries are: Morocco 10 US¢/kWh, Jordan 7 US¢/kWh, Tunisia 4.6 US¢/kWh, and Egypt 2.8 US¢/kWh.

Graph 2.5: Regional Tariffs in US¢/kWh



Source: Compiled by the World Bank, 2007.

2.16 However, in the region, Lebanon presents more similarities with countries dependent on imported fuel for power generation, such as Morocco and Jordan, and the Lebanese tariff level is comparable to these countries. The fuel import structure of the comparable countries, however, is different. In Morocco, power generation is dependent on imported coal, HFO, and to a lesser extent natural gas, but not gas oil, while Jordan does not import any gas oil. In contrast, Lebanon is in a unique situation for a non-landlocked country to depend on gas-oil for half of its fuel (1.10

[25] Outsourcing of commercial and billing functions is increasingly popular with utilities worldwide, and particularly in emerging markets where the issue is more with effectiveness and integrity of the billing and collection functions than with the cost of these functions. Recent examples of outsourcing to combat billing and metering fraud can be found in India and Nigeria.

million tons of gas oil against 1.0 million tons of HFO in 2006), with a considerable cost penalty, given the premium price of gas oil[26].

2.17 According to sector regulation, the electricity tariff is set and approved by the Ministry of Energy and Water (MOEW), based on EdL's recommendation. It has been practice to also have the tariff approved by the Council of Ministers. The current tariff structure is based on an oil price of US$25/barrel[27] and has not been adjusted to take into account the massive increase in the international oil price in recent years, partly due to continued service un-reliability which results in any tariff increase likely to be met by protest by consumers and a significant decline in the billing and collections. The 2006 tariff structure is presented in Annex 1.

<u>Tariff Structure</u>

2.18 Besides the level of the tariff, there are also opportunities to improve the tariff structure. The residential tariff subsidizes the lower tranches of consumption through an inverted block tariff, as is frequently the case in other countries, but the tranches are wide and the inverted block tariff usually peaks at about 300 kWh instead of the 500 kWh threshold retained in Lebanon at present. Indeed, consumers with a consumption of electricity in excess of 300 kWh may not qualify as economically vulnerable.

2.19 The tariff to existing concessions in the distribution of electricity in specific geographical areas (Zahle, Jbeil, Aley and Bhamdoun) is 5 US¢/kWh, almost half of the average tariff. The concessionaires in turn sell the electricity supplied by EdL at about 10 US¢/kWh earning a margin of 5 US¢/kWh. This is a very significant distribution margin; a normal distribution margin ranges between 1.5 to 2 US¢/kWh. The loss to EdL amounts to about US$20 million per year based on sales of about 900-1000 GWh, which will increase to over US$40 million per year by 2015 (see Chapter 5). It is unclear how this agreement is regulated and by whom.

2.20 For industrial users, the tariff structure actually encourages self-generation during peak periods. The average tariff for industry consumers is 10 US¢/kWh, but it is 21US¢/kWh at peak hours which is close to or above the cost of self generation using HFO (for which the variable cost is 10 to 12 US¢/kWh and the fixed cost about 8 US¢/kWh at a 30% load factor). This in turn reduces EdL's revenue base which is an issue since these users are generally more reliable and paying customers. The existing tariff structure therefore makes it financially attractive for large and medium size industries to shift to self-generation. For middle and high income residential consumers and large residential buildings, once they have purchased a generator to protect against power supply un-reliability, the cost of running their generator is competitive against the EdL tariff: for residential and commercial consumers, the tariff applied to each kWh consumed above the 500 kWh threshold[28] is about 13 US¢/kWh, which is close to the variable cost of a small diesel unit for self-generation.

2.21 The electricity tariff in Lebanon raises two major issues: (i) it is presently well below the cost of production of electricity by EdL at the prevailing high price of oil; and for large users at

[26] US$614/ton for diesel (gas oil) and US$368/ton for 1% fuel oil (based on actual 2006 prices paid by EdL).
[27] Source: EdL.
[28] The "lifeline" level for residential consumers is 500 kWh. The first 500 kWh are billed at a low tariff of about 5 US¢/kWh. Consumption above 500 kWh is billed at 13 US¢/kWh.

peak periods, higher than self-generation cost; and (ii) its structure needs to be revised to be competitive in order to capture the large (paying) consumers and better target any subsidies that may be warranted to vulnerable consumers. Regarding the first issue, the continued use of gas oil and the high losses make EdL uncompetitive. If EdL was using natural gas instead of gas oil (as is optimal for CCGTs), the cost of production could be drastically reduced (see Chapter 4). On the structure of the tariff, consultants have recently been recruited as part of a Technical Assistance Project co-funded by a World Bank grant to restructure EdL. This project includes consulting services to the MOEW and involves a mandate to review recent tariff studies and to develop an action plan for new tariffs with an implementation plan that is commensurate with the improvement in sector performance.

2.22 More specifically, the ToRs of the consulting services to the MOEW in this regard call for "*support to the Ministry in the integration of the power sector least cost plan (i.e., the Master Plan), review recent tariff studies and update these and formulate an action plan, and prepare a fuel sourcing strategy. This will be presented in a medium and long term national energy strategy*".

IV. FUTURE DEMAND

2.23 To identify the investment needs in the sector, projections of future demand for electricity have been produced. The various scenarios and assumptions used are described below.

Demand and GDP

2.24 Future demand is largely determined by GDP growth and future electricity prices. In Lebanon, the demand to be met by EdL also depends on whether EdL can recapture some of the demand currently met by self-generation. As a first cut, it has been assumed that electricity prices will remain at current levels and projections have been prepared for future electricity demand for energy in kWh (amount of energy used during the year) and capacity in MW (maximum generation capacity of the power system needed to meet the peak demand at any point in time during the year) under three scenarios: Base, Low and High Case GDP growth.

2.25 The assumptions for GDP growth are based on the World Bank's Interim Strategy Note (ISN) for Lebanon prepared in July, 2007. The GDP growth forecast presented in the ISN provide for the Base Case scenario which has GDP projected to increase by 4.5% in 2009 and 5% p.a. thereafter[29]. The Base Case also assumes that self-generation will maintain its present share in meeting consumer demand; i.e., 67% for industry and 11% in other categories, and therefore will be kept constant over time (i.e., no capture of the self-generation market by EdL).

2.26 For the purposes of this report, a Low Case and a High Case has been prepared to assess the impact on the demand forecast and the need for new investment in generation capacity. In the Low Case scenario, GDP is projected to grow by 2.9% in 2009, 2010 and 2011 and 3% p.a. thereafter. In the High Case scenario, GDP growth is projected at 5% in 2009 and 2010 and 5.5% thereafter (See Table 2.2 below). The growth figures for the Low and High Case scenarios

[29] Lebanon Interim Strategy Note, World Bank, July 2007

were selected by the World Bank Team that prepared this report to provide sufficient difference to the Base Case.

Table 2.2: Summary of GDP Growth Scenarios

GDP Growth Scenarios	2008	2009	2010	2011	2012	2013	2014	2015
High Case	4.7%	5.0%	5.0%	5.5%	5.5%	5.5%	5.5%	5.5%
Base case	**3.5%**	**4.5%**	**5.0%**	**5.0%**	**5.0%**	**5.0%**	**5.0%**	**5.0%**
Low Case	2.9%	2.9%	2.9%	2.9%	3.0%	3.0%	3.0%	3.0%

Demand Elasticity

2.27 Another key parameter in determining future demand is the demand elasticity to GDP growth.[30] The GDP elasticity of the demand varies with the level of country development. Countries at an early stage of development tend to have a higher GDP elasticity of 1.3 or above, as growth may be driven by relatively energy intensive industries and the modernization of the energy consumption pattern involves a shift from traditional energies to electricity. For high-level intermediate countries, such as Lebanon, growth is driven more by service activities than energy intensive industries, and the modernization of consumption patterns is already well advanced. In such case, the elasticity may range from 1.1 to 1.2. For advanced countries, where growth originated mainly in services, energy intensive industries are declining and the consumption pattern is fully modernized, the elasticity is 1.1 and, occasionally, below 1.

Table 2.3: Summary of Elasticity Assumptions

Demand Elasticity Assumptions	2008	2009	2010	2011	2012	2013	2014	2015
Price Elasticity	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Income (GDP) Elasticities								
Private LT	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Private HT	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
Government LT	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Concessions	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15

Note: price elasticity presented in the table above are used in determining the impact on demand from a possible tariff increase presented later in this chapter.

2.28 In the case of Lebanon, the GDP elasticity of high voltage consumers was estimated at 1.15, reflecting the role of services in the projected Lebanese growth. For low voltage consumers, it was considered that the modernization of consumption patterns is well advanced, but not completed (updating of appliances, air conditioning units, water heaters, etc), so an elasticity of 1.2 was retained. For Government administration, an elasticity of 1.1 was retained, as some, but limited, modernization can still be expected in the future (see Table 2.3 above). Detailed assumptions for each of the scenarios are presented in the tables in Annex 1.

Forecast of Total Electricity Demand

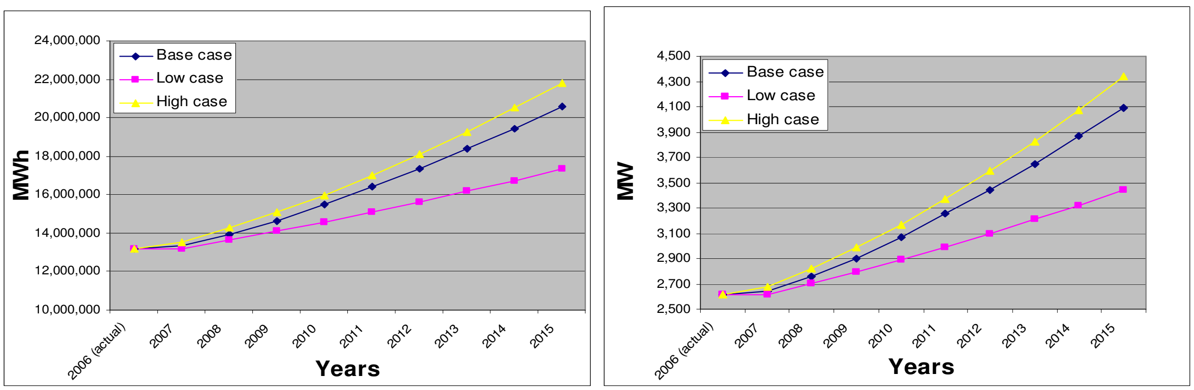
[30] It is assumed that no price increase will be applied over the period.

2.29 Using the GDP growth and elasticity assumptions outlined above, electricity demand has been forecast under three scenarios (Base, Low and High Case).

Base Case

2.30 Under the Base Case scenario, it is forecast that the total demand for electricity will increase to 5.9% p.a. from 2010 onward. Based on this forecast, Lebanon (EdL and self-generation) would need to add an additional 1,500 MW by 2015 (see Graph 2.6 below) to meet total demand of 4,000 MW. Under the Low Case, the additional capacity required would be about 700 MW and in the High Case, 1,700 MW.

Graph 2.6: Projected future total demand for electricity (EdL plus self-generation) 2006-2015



Source: World Bank Analysis, 2007.

<u>Forecast of Electricity Demand to be Met by EdL</u>

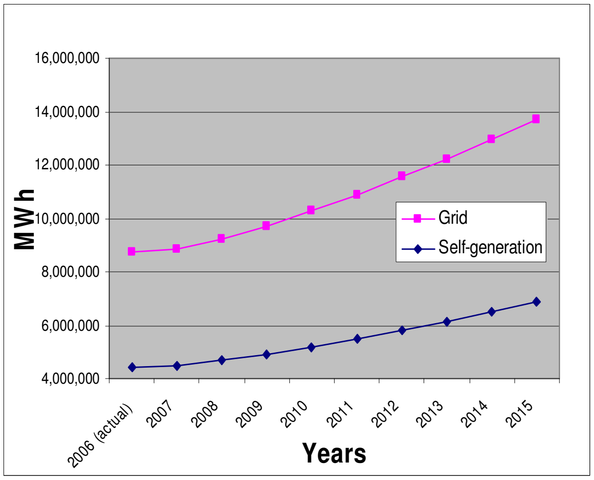
2.31 Now that scenarios for forecast total demand have been established, the demand that could be met by EdL needs to be assessed. This will be driven by what EdL will be capable of supplying, including its ability to capture demand currently met by self-generation. Under the Base Case scenario, EdL is not projected to capture any of the market share currently served by self-generation, and therefore, to maintain its share of the overall demand, EdL would be required to ensure the installation or availability (through loss reduction) of an additional 1,000 MW (67% of 1,500) by 2015. In other words, it is assumed that EdL can only continue to meet the annual increase in demand at its current share of overall demand. This will be challenging enough, even under a process of restructuring.

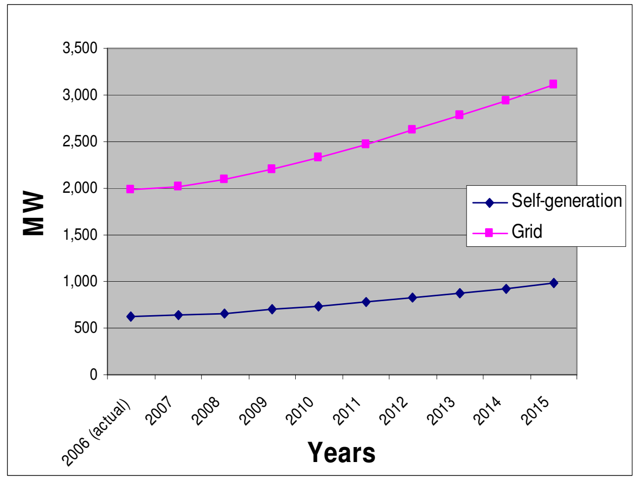
2.32 Regardless of which demand scenario materializes, having sufficient capacity to meet the demand will require that: (i) EdL is restructured quickly and significantly to be able to handle the implementation of a significant investment program of 130-170 MW of new capacity per year. The development of the new capacity under private sector financing and management would facilitate meeting the growth target of the grid-based system, but still require a fundamental change in the organization and management of EdL for it to sustainably play the role of off-taker[31]; and (ii) the creditworthiness of the power sector is improved drastically as the financial obligations resulting from new investment ultimately fall on EdL, either through the

[31] Assuming the IPP sells to the grid (the transmission company under the envisioned restructuring of EdL).

generation of a cash flow sufficient to support public sector investment, or through long term Power Purchase Agreements, in the case of a private sector driven investment program.

Graph 2.7: Demand to be Met by EdL 2006-2015



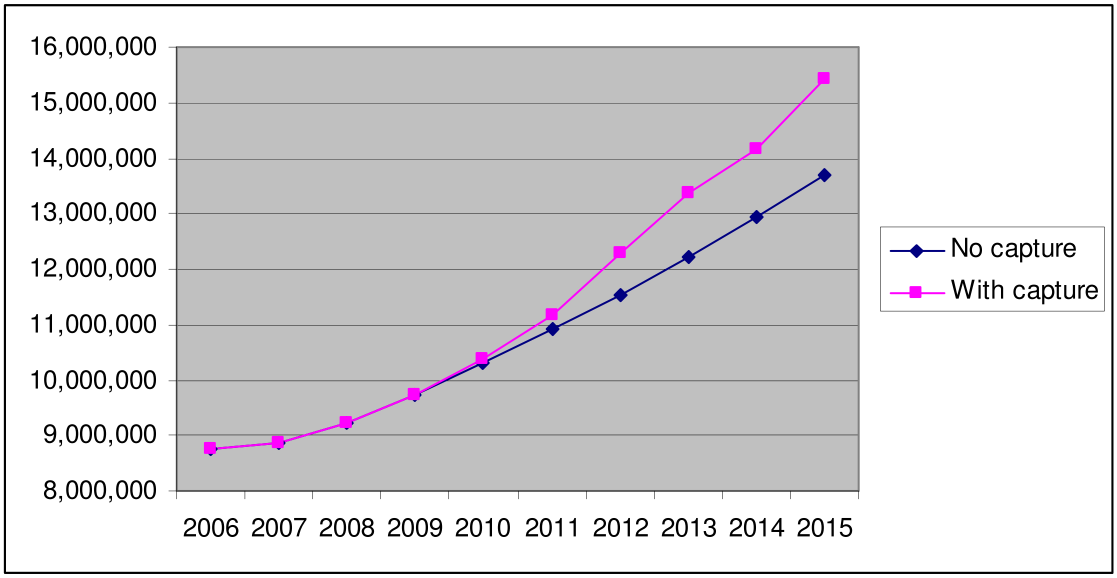


Source: World Bank Analysis, 2007.

<u>Forecast of Demand to be met by EdL if some self-generation is captured</u>

2.33 If a strategy is adopted whereby EdL progressively captures some self-generation with a goal of reducing self-generation to, for example, 50% of the industry needs (compared to 67% at present), 8% of low voltage needs (compared to 11% at present), and 9% of government needs (compared to 11% at present), the increase in demand to be met by the grid will be higher, and the energy demand to be met by EdL is estimated to increase by between 6% and 9% per year with a demand to be met by EdL by 2015 amounting to 3,339 MW of capacity (15,400 GWh), compared to 3,100 MW (13,600 GWh) without capture of self-generation.

Graph 2.8: Comparison of EdL forecast supply with and without capture (MWh)

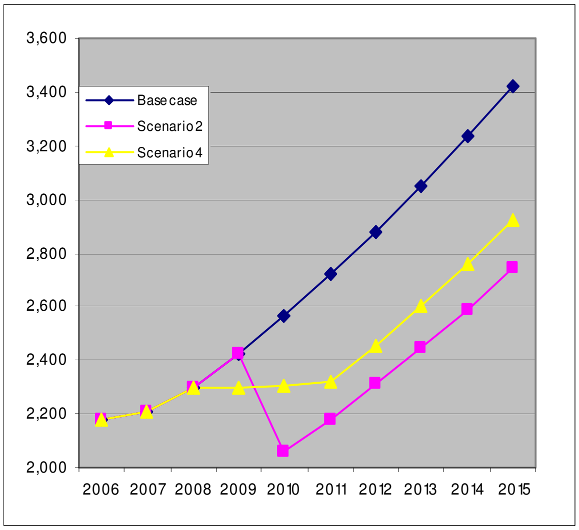


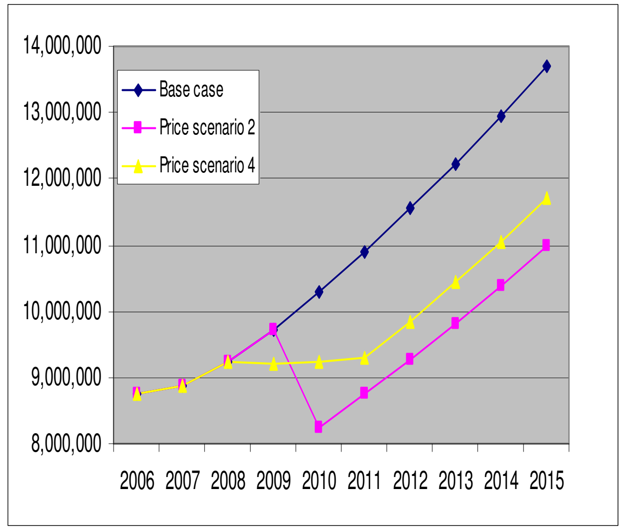
Source: World Bank Analysis, 2007.

Impact of Tariff Increase:

2.34 None of the scenarios above assume any changes to the current tariff. Nevertheless, it is important to assess – even broadly - the potential impact on demand due to an increase in electricity prices. Chapter 4 analyzes the tariff increase necessary to cover cost and reduce subsidies under various reform scenarios. Two additional price scenarios were tested, which are described in more details in Chapter 4 below: A one-shot increase of the tariff by 99.2% in 2010 (scenatio 2 of Chapter 4) and a gradual increase of 26.5% in 2009, 26.5% in 2010 and 24.5% in 2011 (scenario 4 of Chapter 4) using the elasticity assumptions presented above in Table 2.3. 50% was used as a reference point. Chapter 4 analyzes the tariff increase necessary to cover cost and reduce subsidies under various reform scenarios. The result shows under scenario 2 a possible 14.8% reduction in the demand to be met by EdL by 2015. Electricity demand would reach 10,991 under scenario 2 to 11,693 GWh under scenario 4 in 2015, compared to 13,711 GWh under the Base Case, and 2,745 to 2,921 MW of capacity compared to 3,425 MW in the Base case. See Graph 2.9 below.

Graph 2.9: Impact of price increase on demand to be met by EdL (GWh)





Source: World Bank Analysis, 2007.

Chapter 3: Supply Options and Impact on Public Spending

EdL's currently available capacity is at best about 60% of peak demand for electricity in Lebanon[32]*. As a result, it is forced to operate all plants at maximum load which comes at a high cost since some of its plants are peaking plants which have low fuel efficiency. Adding capacity is a matter of highest priority in Lebanon, at the same time losses are high so new generation should be added in parallel to a loss reduction program. In this context, all existing plants must be better maintained and Zoul and Jieh should be rehabilitated to extend their life and ensure continued capacity availability. The cost-benefit of this is very clear as demonstrated in this Chapter. Under no scenarios analyzed in this chapter, does operating CCGTs on gas-oil for a longer period of time make economic sense.*

I. Supply of Electricity in Lebanon

Introduction

3.1 EdL's total installed power supply capacity was 2,100 MW at the end of 2006, of which 1,900 MW consisted of thermal power capacity, and the remaining hydro. However, available supply has been drastically reduced in the past few years due to several major – and often unforeseen – events: (i) restoration requirements of the gas turbines at the Beddawi and Zahrani power plants; (ii) a fire at the Zouk Power Plant (Unit 3); (iii) fuel supply problems due to the destruction of fuel tanks at the Jieh Power Plant during the hostilities with Israel in July 2006; and (iv) most recently, the destruction of parts of the Beddawi power plant (cables and water piping in particular) in conjunction with the fighting in the area of the Nahr El-Bared Camp. As of January, 2008, available capacity was reported (by EdL) to be 1,562 MW. It was as low as 1,100 MW at the end of the summer in 2007 following the fighting in the Nah El-Bared Camp and fuel supply problems/shortages at the other plants. Annex 2 presents a table of Lebanon's thermal power plants, their installed capacity and currently available capacity.

3.2 Most of Lebanon's thermal plants operate mainly as base or intermediate load plants (i.e., operating all the time at full available capacity) since supply capacity is insufficient to meet demand; with several scheduled and unscheduled outages. However, as restoration to full capacity of existing plants is achieved and new capacity is added, the dispatch of electricity and thus the operating schemes of each plant should be based on economic merit. This will allow for least-cost generation of electricity at all times and may result in the relatively small gas oil fired units (e.g., the Tyre and Baalbeck plants) taking the exclusive role of peaking units to meet peak demand.

[32] 1,562 MW divided by 2,614 MW (This is probably over-estimated since the 1,562 figure is based on 2008 and the 2,614 is from 2006 and likely to have increased since then).

3.3 As described in Chapter 2, there is a significant difference between peak demand and base load demand in Lebanon, with peak reaching above 2,614 MW in 2006 (this includes EdL's supply, imports and supply by self-generation; i.e., system-wide demand)[33]. The difference between peak demand and EdL's ability to meet demand is filled by self-generation, imports from Syria and from time to time significant rationing of supply. The maximum import capacity from Syria is 300 MW. In 2006, Lebanon imported up to 200 MW at a price of approximately 12 US¢/kWh.

Fuel Supply

3.4 EdL's six power plants currently operate on either gas-oil or fuel-oil. Purchase contracts have been entered into for fuel procurement with Kuwait Petroleum Corporation, KPC and Sonatrach of Algeria. The contracts were entered into in 2005 and are for a three year term. The quantities are determined based on schedules provided by EdL every three months and the size of the shipments vary between 35,000-60,000 tons.

3.5 The price for the fuel is specified in the contracts and is based on either CIF or FOB terms[34]. The cost of the fuel is based on a formula that calculates an average market price in the region based on PLATTs[35]. A premium is added which varies with the size of the cargo (decreases as shipments increase in size) from US$7.95 to US$5.95 per barrel. There is also a 10% VAT applied to the cost.[36] EdL covers the cost of transportation of the fuel to the power plants, when applicable[37]. Private companies are employed to inspect the fuel at loading and discharge under contracts with the MoEW.

3.6 EdL pays for the fuel through Letters of Credit (L/C) that has been opened by MOEW with the Central Bank (Banque du Liban). The L/Cs are guaranteed by the Ministry of Finance which implies that when EdL cannot pay for fuel purchases, MOF pays on its behalf. The contribution of EdL towards the fuel bill was 20% in 2006 and 12% until the end of November in 2007[38]. There have been several recent reports of interrupted supply as a result of fuel shortage due to delayed approval of the L/Cs or risk of interrupted supply due to fuel shortage. In case of extended payment (which is provisioned for in the contracts), interest is charged in the order of LIBOR plus 1% for KPC and 1.5% for Sonatrach purchases. For self-generation, owners purchase fuel directly from the Tripoli and Zahrani Oil Installations (old refineries now used for storage).

Lebanon's Power Plants

[33] According to EdL the total demand figure was closer to 2,200 MW.
[34] CIF means the selling price includes the cost of the goods, transport costs and also the cost of insurance, and FOB means the seller pays for transportation of the goods to the port of shipment, plus loading costs. The buyer pays freight, insurance, unloading costs and transportation from the port of destination to the power plant.
[35] Gulf average of the previous month for KPC and PLATT's Gulf FOB for SONATRACH gas oil, and PLATT's CIF MED for SONATRACH fuel oil.
[36] Source: Petroleum Directorate, MOEW.
[37] US ¢ents 10/ton is charged to EdL for maintenance of the fuel pipe line transporting the fuel to the power plant. The respective contracts determine the loading point which may be the port or the power plants; in which case there is no transport cost.
[38] Source: Ministry of Finance. According to EdL, the EdL contribution reached 17% by the end of November 2007.

Zouk:

3.7 Zouk, Lebanon's largest power plant, is located in a residential area and local environmental pollution from the power plant is an issue. Unit #3 caught on fire in December 2005 and at the time this report was written the unit had not yet been restored. A contract was signed with Alstom/ABB in August 2007 and an L/C has been opened. The unit is expected to be completed by November 2008. Lack of spare parts, plant engineers and overall staffing reduces the power output and efficiency significantly below the designed value (see Table 3.1 below).

3.8 The Zouk plant runs on fuel-oil. The fuel consumption design value varies from 215 grams/kWh to 225 grams/kWh. The variation is due to the difference in the unit size, with larger units utilizing fuel more efficiently[39]. Based on data collected at EdL and site visit to the plant, the actual fuel consumption is above the design value by as much as 20% for Unit #1. The deviation from the design value has a significant impact on the fuel bill, reflecting an increase in fuel cost by about US$24.1 million in 2006[40]. The higher heat consumption is due to overall deterioration of the plant components, lack of spare parts, and inappropriate operation and maintenance practices. Please note that the detailed savings potential in chapter 4 reflects that it is not expected that, once rehabilitated, fuel consumption would be equal to the design value. The same goes for Jieh below.

Table 3.1: Zouk's efficiency measured by fuel consumption and fuel requirement

Unit No.	Fuel consumption – Design value (gr/kWh)	Actual value in 2006 (gr/KWh)	Deviation from Design Value
1	224.8	267.4	19%
2	223.3	251.5	13%
3	223.7	-	
4	215.8	241.8	12%

Note: Heat content of fuel oil is assumed: 40,600 kJ/kg or 9,700 kcal/kg

Jieh:

3.9 Jieh is the oldest operating plant among EdL's plants. As mentioned above, during the hostilities with Israel the fuel oil storage tanks at the Jieh plant were bombed and caught on fire. Leaks of 15,000 tons of fuel oil contaminated the coast of much of northern Lebanon (150 km), and caused the most severe environmental disaster in Lebanon to date. By the end of 2006, the fuel tank yard had been cleared, and new fuel tanks are under construction with assistance from the Government of Egypt. The first fuel (storage) tank (25,000 tons: around one month of storage) is expected to be completed by mid-February 2008; with the remainder by the end of 2008. As a temporary measure, fuel oil is supplied by truck tankers from one of Lebanon's non-operational refineries. Forty to fifty trucks are arriving to the plant daily (1,500 - 1,600 ton/day),

[39] Units 1-3 are 140 MW and Unit 4 is 170 MW.
[40] See Annex 3 for detailed calculation.

but it is not sufficient to keep the plant operating at full load, causing an additional burden on the system's ability to meet demand.

3.10 As in the case of Zouk, the actual value for fuel compared to the design value varies by as much as 31% for Unit #2. The deviation represents an increase in fuel cost of US$28.4 million[41]. The higher fuel consumption design value for Jieh as compared to Zouk are due to the fact that Jieh's units are smaller and older than Zouk's.

Table 3.2: Jieh's efficiency measured by fuel consumption and fuel requirement

Unit No.	Fuel consumption – Design value (gr/kWh)	Actual value in 2006 (gr/kWh)	Deviation from Design Value
1	250	310	24%
2	250	328	31%
3	240	286	19%
4	240	288	20%
5	240	288	20%

Note: Fuel heat content is assumed: 40,600 kJ/kg or 9,700 kcal/kg

3.11 Jieh is overdue for overhaul. Table 3.3 below shows the hours of operation of the plant. The maximum allowable operating hours after the last overhaul is expected to be 90,000 hours. Unit 3 requires immediate overhaul.

Table 3.3: Jieh's operating hours

Unit No.	Operating hours from the start of commercial operation	Operating hours since last overhaul	Operating hours in 2006
1	181,484	81,562	4,344
2	186,316	78,916	4,140
3	148,386	96,564	6,331
4	157,321	41,061	6,259
5	158,318	84,827	5,998

3.12 The life of both Zouk and Jieh could, through plant refurbishment, be prolonged by about ten years (see next section on proposed investment for additional generation capacity). The life of the power plants depends on the practice of maintenance and operation. As skilled workers are retiring or leaving the plants, capacity building of O&M staff and new permanent operation and maintenance staff are necessary to keep the plants at reliable operation conditions.

[41] See Annex 3 for detailed calculation.

Beddawi and Zahrani Combined Cycle Power Plants

3.13 The two most recently constructed power plants are the Combined Cycle Gas Turbines (CCGTs): Beddawi and Zahrani. These plants each have installed capacity of 435 MW and make up about half of Lebanon's generation capacity. As the most recently added plants, these are important assets in the power system. However, they are not operating under optimal conditions. The most pressing issue is that they use a very uneconomical fuel, gas-oil (diesel oil). Although CCGTs are designed to operate on either natural gas or gas-oil, operation on gas-oil can render this generation technology un-economical despite its higher fuel efficiency (50% compared to 38-40% for steam-cycle plants). This is because the price of gas-oil tends to be double that of natural gas to feed the same energy input (see Chapter 4).

3.14 The decision in Lebanon to procure this type of technology was based on plans to import natural gas from Syria. To this effect, an agreement was entered into between the Governments of Lebanon and Syria in 2003. The agreement provided for sufficient natural gas to supply one plant (around 1.5 bcm per year at 80% load factor). A gas pipeline was constructed between the Syria border (at Homs) to the Beddawi power plant in Lebanon[42]. The pipeline was completed in 2005 but due to insufficient gas in Syria to meet domestic demand, Lebanon is not yet importing gas through this pipeline. In April 2007, an agreement was signed with Egypt to import Egyptian natural gas via Syria on the Arab Gas Pipeline. To allow for this, the pipeline infrastructure needs to be completed between Jordan and Syria (on the Jordanian side). This is reported to have been completed. The Egyptian gas is expected to be delivered to Lebanon in the second quarter of 2008, assuming no commercial or political obstacles to supply or transit gas. Currently, there is no infrastructure in place to transport the gas further to Zahrani in the south of Lebanon. Options are under consideration, including construction of domestic pipeline connecting Beddawi and Zahrani as well as LNG directly to Zahrani.

3.15 Another issue is EdL's inability to properly maintain these plants. To address this issue, an operation and maintenance contract was signed with KELECo (a Korean and Lebanese contractor) in 2005 for a five-year period at a value of US$86 million. However, maintenance issues have surfaced which may have been overlooked in the contract. These include for example the maintenance of the gas turbine - a Siemens silo type which is no longer manufactured – and of which KELECo staff do not have experience. Also there seems to have been an underestimation in the cost of spare parts which has resulted in use of alternative spare parts for the gas turbine which may cause serious failure of the gas turbines in the future. To handle this issue, including arbitration, a supervision contract for the O&M contract is about to be signed since EdL also has difficulty in representing the interest of the sector and properly negotiating contracts due to lack of skilled staff.

3.16 In addition, the gas turbines (stators) at both Beddawi and Zahrani suffered from manufacturing defects in 2006 and 2007, causing the plants to operate at half load. Temporary measures were taken and units were put back into operation in early 2007. However, until the stators have been permanently replaced, the plants run a high risk of generator failure. The Beddawi plant has also suffered from the fighting at the Nahr El-Bared Camp in August. After the power plant was restored in mid August, it operated at full capacity due to favorable ambient

[42] The Gasyle pipeline: 32 kilometers and capable of transporting 3 million cubic meters (mmcm) per day.

temperature until mid October when GT2 was shut down due to scheduled maintenance. It is expected to be completed by December 2007/January 2008, leaving current total capacity of Beddawi at 200 MW (GT1 130 MW and steam turbine 70 MW). At the time of writing this report, Zahrani was reported to be operating at half load as well (GT2 and steam turbine) to save fuel.

Table 3.4: Efficiency (fuel consumption) and operating hours of Beddawi and Zahrani plants

	Unit No.	Design efficiency (%)	Actual efficiency (%)	Availability in 2006	Operating hours in 2006	Operating hours in 2007 to date	Operating hours (cumulative)
Beddawi	GT1		31.88		5,015	7,274	67,411
	GT2		32.24		8,851	2,876	66,645
	CC plant	50.7	48.23	78.26%	8,131	6,094	43,127
Zahrani	GT1		31.93	97.56%	10,653	8,374	83,202
	GT2		32.13	96.95%	7,993	6,911	77,321
	CC plant	50.7	46.96	92.66%	8,259	7,190	54,407

Note: Fuel heat content is reported as follows: Zahrani (GT1 11,290 kj/kwh; 11,166 kj/kwh; plant heat rate 74,650 kj/kwh).

3.17 As illustrated in Table 3.4 above, the actual power plant efficiency is lower than the designed efficiency since neither plant tends to operate at full capacity either due to gas turbine steam turbine failures, overhauls and/or fuel supply constraints.

II. Meeting Future Needs

3.18 Given that there is already a deficit in available capacity to meet demand; the Government needs to quickly identify the least-cost options concerning additional capacity. An Electricity Sector Master Plan covering the generation and transmission segments is under preparation by EDF. The Master Plan will identify the least-cost options for Lebanon using least cost expansion planning techniques. This PER has undertaken some preliminary analysis to review options which should be further analyzed and assessed in the context of the Master Plan.

3.19 Based on the base case demand scenario, an additional 350 MW and 1,300 MW are needed by 2010 and 2015, respectively to meet demand without any reserve margin and assuming that the share of self-generation is maintained constant.

3.20 To add capacity to the system, four options are recommended to be pursued **in parallel**:

(i) Improvement of dispatch;
(ii) Reduction in technical losses;
(iii) Rehabilitation of existing steam cycle plants; and
(iv) Construction of new capacity.

(i) Improvement of dispatch

3.21 One of the weaknesses of the Lebanese power system is the ineffective dispatch of generation capacity to meet the demand at the least cost. A contract was recently awarded to construct a National Control Center (expected to be operational in 2008) which will help ensure that at each point in time, the least expensive units are called in priority to meet the demand. The absence of optimal dispatch is costly in terms of fuel consumption. However, since EdL's available capacity is insufficient to meet demand at several points during a 24 hour period; all units have to run at full load often during the 24 hour period making the role of dispatch less relevant, except during off-peak times. Nevertheless, as available capacity is increased, a modern dispatch center will represent a major step forward for reliability of supply and cost minimization.

3.22 Although it is difficult to estimate the impact of optimal dispatch on fuel costs in Lebanon, the optimization of dispatch of hydro capacity and of thermal plants on a real time basis following the merit order saves about 2%-3% on the fuel bill in a country like Morocco. If the equivalent was the case in Lebanon, the savings would represent about US$24 million. Annex 2 presents the calculation.

3.23 The completion of the new dispatch center should be a matter of priority. In addition, the MOEW and EdL should plan for training to the plant managers to operate their units under the instructions of the dispatch center in real time, and the engineers who will be in charge of the dispatch center should also receive advance training. Training is reported to be included under the NCC contract, but this should be verified.

(ii) Reduction of technical losses

3.24 Reducing the technical losses would free-up generated electricity to meet demand. This would have the two-fold benefit of increasing available supply and turning produced electricity into billable electricity. At 15% losses, the scope for reduction is sizeable but will never be completely eliminated since among some of the most efficient power systems, losses seldom come under 7-8%. For Lebanon, this report estimates that the losses can be reduced to 10% by rehabilitation and repair of the network and by 2012 (in line with the Government's plan), which would increase the electricity supply by about 100 MW equivalent, or 400 GWh (based on 2007 capacity.)

3.25 According to planning engineers at EdL, the following investments are necessary to reduce losses and optimize supply in the network.

- transformers for 66 kV/MV, 220 kV (or 150kV)/66kV, 220 kV/MV
- Sub stations 66kV at Oyoun, 220 kV at suburbs of Beirut
- Underground cable 220 kV between Aramourn and Pins
- Rehabilitation of 66kV lines (20Km)
- Rehabilitation of Pilot Cable and connection) (20km)
- Rehabilitation of Overhead line 66kV (300km)
- Rehabilitation of Sub-stations 66kV

3.26 Based on discussions with EdL staff and international experience, the cost to undertake the above is estimated to be around US$200 million over the next five years, i.e., US$40 million annually. Annex 2 presents the cost-benefit of undertaking these investments. As the Annex 2 presents, the pay back time, using a 12% discount rate, would be 12 years from the beginning of the full program[43]. Given the long period it would require to benefit from these investments, it is recommended that the proposed investments are carefully reviewed in the context of the Master Plan to ensure that they are merited and economical. Furthermore, they represent mainly investment in transmission, whereas most losses are presumably in the distribution network. Therefore, the investment needs in the distribution network need to be added. Having said that, although the pay back period appears very long and might trigger questions about the economic merit of undertaking the investments, addressing losses (technical and non-technical) should remain a top priority for the government to ensure that (expensively) produced electricity can be billed to the largest extent possible. Achieving loss reduction is also a very visible sign to consumers that the government is addressing the sector problems, and hence an important measure to improve sector governance.

3.27 In parallel with addressing the technical losses, the 17.8% of non-technical losses (un-billed and stolen electricity) as well as the 10% of uncollected billed electricity also need to be addressed. It is important to note that both the technical and non-technical losses are included in the scope of work to be addressed under the management contracts that CRA International is helping the government solicit to the distribution segment (see Chapter 5).

3.28 The Public Investment Program presented by the Government during the Lebanon Core Group Meeting in Washington, DC on October 16, 2007 includes investment in transmission and distribution for US$215.3 million and US$82.7 million, respectively. The US$215.3 million is assumed to cover reflect the estimated US$200 million in investment requirements described above. The US$82.7 million is assumed to be repairs and upgrades to the distribution network, but excluding the planned installation of remote meters which the Government intends to mobilize from the private sector.

(iii) Rehabilitation of existing steam cycle plants

3.29 As part of this review, a preliminary assessment was carried out on the feasibility of rehabilitating Zouk and Jieh Power Plants. The conclusion is that these two plants could operate for up to an additional ten years provided they are rehabilitated and then properly maintained and operated. The restoration and rehabilitation of these plants, which can be implemented within 2-3 years, would be a cost-effective way to increase available capacity in the short term.

3.30 At present, the Zouk and Jieh steam plants are operating at reduced capacity due to fuel supply capacity problems (Jieh), lack of spare parts and overdue overhauls. The plant efficiency in terms of fuel/kWh produced is around 15-25% lower than the design level.

3.31 Based on international experience and visits to the power plants, it is this review's assessment that both plants can be rehabilitated at a cost of around US$100 million each, including investment required for environmental control systems. In addition, a further US$10

[43] Assuming that the program is implemented over 5 years.

million per year per plant would be needed to maintain a normal level of maintenance for the plants. When the capacity and efficiency is restored closer to the design value, these two plants could provide additional capacity of 130 MW. The Government's Public Investment Program has rehabilitation of existing capacity estimated at US$117.5 million, whereas this report estimates the needs at US$100 million per plant. KELECo has also made some estimates which suggested that Zouk could be rehabilitated a lower cost than the World Bank estimate. The forthcoming Master Plan should confirm. If it is not included in the scope of the Master Plan then it is recommended that both Jieh and Zouk be studied as a matter of urgency to arrive at accurate cost estimates and commence the tendering process for rehabilitation (partial or full).

3.32 The economic justification for the rehabilitation of these two plants, based on a preliminary estimate, is highly economical, with an Internal Rate of Return of 27% for Zouk and 20% for Jieh, and a respective pay-back of three and five years after completion of the rehabilitation.[44] Annex 2 presents the calculation.

(iv) New Generation Capacity

3.33 In addition to the measures listed above, Lebanon needs to make a decision in the very short-term on new power plant generation capacity. This decision-process involves several factors.

3.34 Firstly, new power plant could be constructed either at new (Greenfield) or at existing power plant sites (Brownfield). The existing power plant sites have the advantage of the ability to use common infrastructure such as water utilities and power transmission routing (although most likely new or reinforced transmission lines would be required to accommodate the increased generation.) The existing power plants may have a disadvantage of space constraints and cumulative environmental pollution problems (e.g., the Zouk site). Whether new capacity is eventually constructed as Greenfield or Brownfield, site specific feasibility studies, taking into account aspects related to economy of scale for fuel supply for example (i.e., fueling an existing as well as new power plant carries economies of scale for fuel supply) will be necessary. Should the natural gas from Egypt be available on time and in sufficient volume, adding capacity in and around the Beddawi site would make sense.

3.35 Another very important decision to make is what technology to consider. The technology choice for new capacity in Lebanon will be largely driven by the fuel options available. This review has analyzed four different options in terms of technology: Large CCGT (450 MW); Medium CCGT (300 MW); Large Steam Cycle (450 MW) and Medium Steam Cycle (300 MW). The fuel options for these technologies are presented in Table 3.5 below"

[44] Assuming that for Zouk, the fuel efficiency will increase by 14.6% and for Jieh, by 22.8%, that the additional generation capacity will be 87 MW for Zouk and 51 MW for Jieh, with an average load factor of 60% and a value of avoided self-generation at $0.13/kWh. The fuel cost is taken as $368 per ton.

Table 3.5: Generation technologies and fuel options

	Piped Gas	**LNG**	**HFO**	**Diesel**	**Coal**
CCGT	Yes	Yes	No	Yes	No
Steam Cycle	Yes	Yes	Yes	No	Yes

3.36 It is important to keep in mind that CCGT is more fuel efficient (50%) compared to Steam Cycle (38-40%), but steam cycle has more fuel options as is shown in the Table above (and can use cheaper fuel: fuel-oil compared to gas-oil and coal). The fuel cost and thus the technology choice is also sensitive to the plant's load factor (i.e., the output of the power plant compared to the maximum output it could produce; a high load factor means fixed costs are spread over more kWh of output and means greater total output). The average load factor for Lebanon's power system was about 60% in 2006 (for all power plants, including base and peaking plants), but new plants would be expected to operate at full capacity (load factor of 85%) assuming they operate as base-load plants.

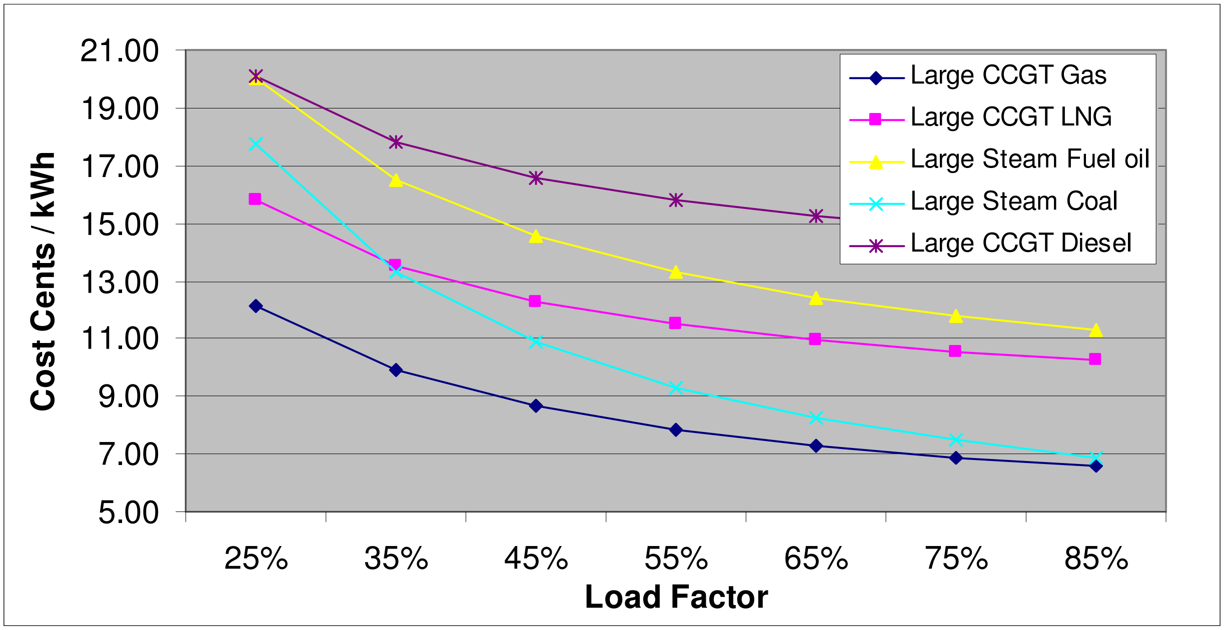
3.37 Graph 3.1 below shows how the different technologies compare across several load factors and fuel options. As the graph shows, if the plant is to be used as a base-load plant and operate at full load, the least cost option for Lebanon would be large gas-fired CCGT units followed by coal-fired Steam Cycle; which comes at almost the same cost at a load factor of 85%. Table 3.6 presents the same information. The assumed prices for the oil based products and the coal are as follows:

Fuel Cost Forecast		**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013***	**2014***	**2015***
Crude Oil Price (IEA forecast) (i)	US$/barrel		71.3	88.5	83.0	81.0	80.5	80.3	77.0	75.1	73.2
Crude Oil Price for Lebanon (ii)	US$/barrel		73.4	91.2	85.5	83.4	82.9	82.7	79.3	77.3	75.3
Diesel (iii)	US$/ton		667.4	828.4	776.9	758.2	753.5	751.1	720.3	702.5	684.7
HFO 1% (iii)	US$/barrel		343.0	425.7	399.2	389.6	387.2	386.0	370.1	361.0	351.9
Australian Coal (iv)	US$/metric ton	49.1	58.1	66.1	63.6	62.6	62.4	62.3	60.7	59.8	58.9

(i) Latest IEA projections, as used by the IMF
* logical suite calculated from the past 5 years)
(ii) 3% mark up to reflect Lebanon's situation
(iii) using similar assumptions of conversions than previous versions (based on crude oil prices), with updated ratios based on historical 2007 DEC fuel prices (leading to the same ratios as when using IEA historical)
(iv) using 2006 price, indexed at 50% to crude oil prices (using an average 47% price ratio, calculated from historical 2003-2007 crude oil and coal prices)

3.38 The prices for piped gas and LNG have been assumed to be constant at US$5.65/mmbtu and US$11/mmbtu, respectively. The rationale for this is that for piped natural gas there is a long-term agreement in place with Egypt. The price reference for LNG is based on recent similar projects world-wide.

Graph 3.1: Production cost per kWh based on load factors:



Note: Annex 2 presents the technical parameters assumed for the different technologies as well as their assumed costs.

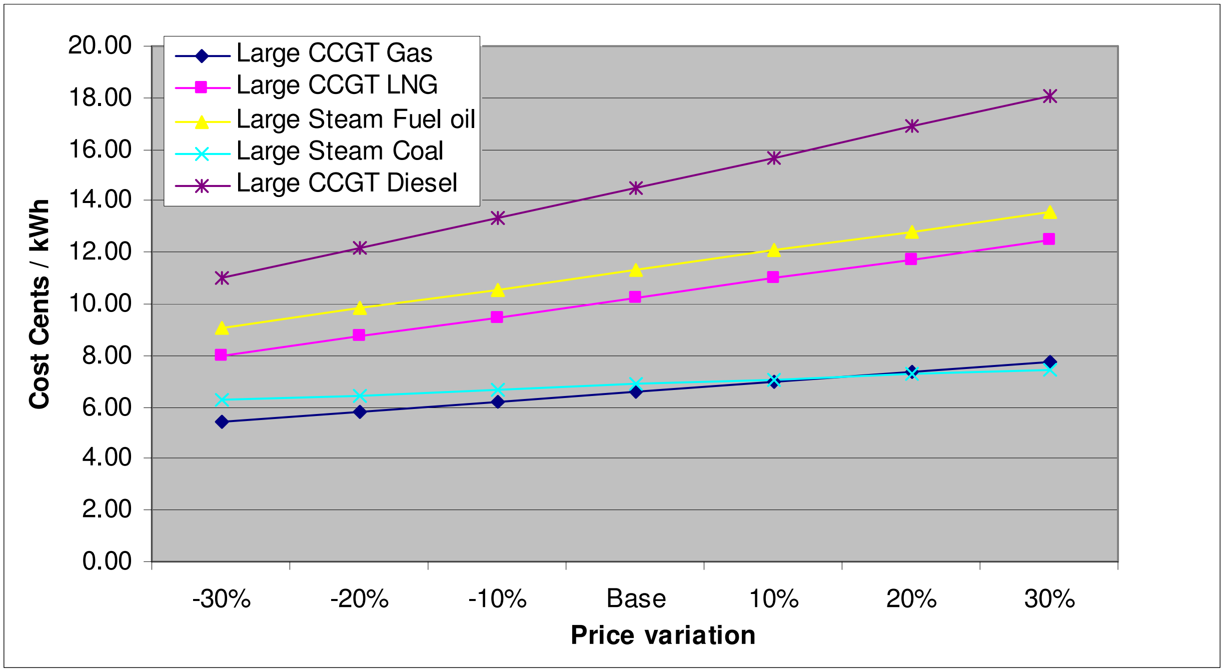
Table 3.6: Production cost for new power plants per kWh based on load factors

	25%	35%	45%	55%	65%	75%	85%
Large CCGT Gas	12.16	9.90	8.65	7.85	7.29	6.89	6.58
Large CCGT LNG	15.82	13.55	12.30	11.50	10.95	10.54	10.23
Large Steam Fuel oil	20.02	16.50	14.54	13.30	12.44	11.80	11.32
Large Steam Coal	17.71	13.32	10.88	9.33	8.26	7.47	6.87
Large CCGT Diesel	20.10	17.84	16.58	15.78	15.23	14.83	14.52

3.39 The Hydrocarbon Strategy Study prepared by the World Bank in 2004 included a comprehensive review of LNG as an option to Lebanon. The conclusions were that LNG is a growing fuel in the region and while more expensive relative to piped natural gas due to the liquefaction and re-gasification processes involved rates higher on the energy security dimension. Lebanon should review the latest possibilities for using LNG, both in terms of supply options (permanent vs. floating re-gasification vessels), anticipated volumes of LNG needed (depending on locations and siting of power plants) and overall energy security and diversification.

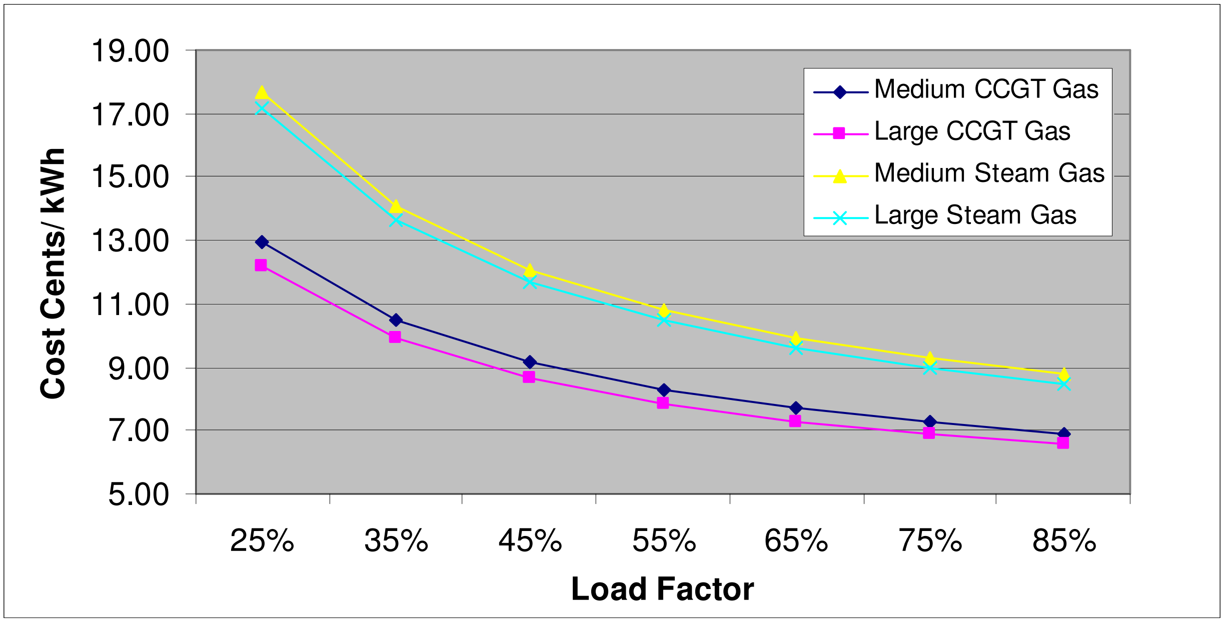
3.40 A sensitivity analysis on the fuel cost shows that at a 30% drop in fuel prices, the large scale CCGT operating on piped gas is least cost since the fuel cost per kWh using natural gas is higher than the equivalent for coal. Should prices increase by 30% on the other hand, large scale steam cycle operating on coal is the least cost option because the fuel component is less affected by the price increase as described above.

Graph 3.2: Technology and fuel choice sensitivity to fuel price changes at 85% load factor



3.41 In addition to the economic merits, the technological choice of any new generation capacity must also be considered in the context of the power system that it is to be integrated into. In this context, Lebanon essentially has a choice of the 300 MW or 450 MW size units. The 300 MW CCGT units are more costly (see graph below) than the larger CCGT units at the assumed fuel prices, a medium sized CCGT unit is more economical than a large Steam cycle unit when operating on gas due to the higher fuel efficiency. However, given the relative small size of the power grid in Lebanon, the smaller unit may provide for more flexibility since they tend to follow the load more easily than larger units and can therefore be utilized to provide peak capacity. It is recommended that the Master Plan carefully reviews the techno-economic merit of larger vs. medium sized units for new generation in the Lebanese power system.

Graph 3.2: Technology and fuel choice sensitivity to load factor variation



<u>Is the introduction of coal as fuel a sensible option for Lebanon?</u>

3.42 Some countries which are completely dependent on imported fuel have opted to diversify their fuel sourcing to include coal (e.g., Morocco, Kenya). As shown above, coal is a much cheaper fuel (US$61/ton). However, coal fired power plants require a number of considerations: (i) construction lead time and investment cost; (ii) environmental aspects; and (iii) imports, logistics and storage.

3.43 <u>Lead time and investment cost</u>: Generally, coal-fired power plants require longer construction time than for example a CCGT. Normally the construction time is 4-5 years, compared to 2-3 years for CCGT. However, at current market conditions with the global surge in energy demand and therefore shortage of manufacturing supply, the lead times could be as long as 5-6 years for coal and 3-4 years for CCGT. The smaller the unit ordered, the longer it tends to take to have it delivered as manufacturers are preoccupied with (and biased to) meeting large orders. The investment cost is also higher at about US$772 million for 500 MW (US$505 million for 300 MW) compared to about US$413 million for 450 MW (US$295 million for 300 MW) for CCGT. However, the lower fuel cost offsets the higher investment costs when comparing the technologies as shown above in Graph 3.1 and Table 3.6.

3.44 <u>Environmental aspects:</u> Coal-fired power plants are often considered as dirty and polluting. In many countries and regions, it is difficult to site and build coal-fired power plants due to lack of local public acceptance and oppositions from environmental NGOs. However, with the drastic fossil fuel price increase in recent years, coal is making a come-back. Technological developments have also mitigated some of the environmental concerns associated with coal-fired power plants. Modern coal-fired power plants are being constructed using state-of-the-art technology under so called clean coal technologies. As a result, local and regional emissions including particulate, SO_2 and NOx can be controlled at a level comparative to natural gas-fired power plants. Emission control devices such as high performance Electrostatic Precipitators (ESP) for particulate control, Flue Gas Desulfurization (FGD) for SO_2 control and Selective Catalitic Reduction Systems (SCR) for NOx control require additional investment and operation and maintenance costs, but the costs are typically less than 20% of the base power plant cost. Ash disposal may be an issue in countries where no appropriate landfill sites are found. Ash can utilized in cement manufacturing, or for construction of buildings, dams and roads. Mercury emissions are regulated in the US, but in new power plants that are equipped with high performance ESP, FGD and SCR no additional equipment cost are usually incurred since these environmental control equipment already remove mercury.

3.45 CO_2 emissions are the most difficult issue as currently no coal-fired power plants are equipped with CO_2 emissions control. However, investment in efficiency measures (such as supercritical power plants, fluidized beds and gasification technologies) are being commercialized and demonstrated in many parts of the world, including China and India, and carbon capture and storage (CCS) technologies are being developed and demonstrated in several parts of the world. EU has also set a target that coal- and gas-fired power plants will be equipped with CCS by 2020 as CSS is an integral part of climate change mitigation.

3.46 Imports, logistics and storage: Coal resources are widely distributed all over the world. This makes coal quite a secure energy. China and the US are the largest coal producers, but they consume most of the cost domestically. Australia, Indonesia, South Africa, Colombia are major suppliers and Japan, Korea, Taiwan, Denmark, Italy are major buyers in the international thermal coal market. The coal can be purchased either from the spot market or under a long term contract. This is quite different from many other fuels such as LNG which usually require long term take or pay contracts. The price of internationally traded coal is affected by the oil price, but is more stable than the price of oil or gas.

3.47 Coal is transported by large vessels (typically from 10,000 ton to 100,000 ton ship) directly from the port of the supplier to the power plant. However, in the European market, there are coal centers in Rotterdam and Amsterdam where coal is received (and sometimes blended) and distributed to power plant sites by smaller vessels or rail road. In Lebanon, coal could be received by ship since most of the power plants are along the coastal area. Coal receiving facilities consist of ship unloaders, belt conveyers, coal yard or storage silos, coal stackers and reclaimers in the coal yard, coal crashing and blending facility. If the power plant is located near residential areas or beaches for tourism, the coal silo storage option is recommended as it prevents coal dust dispersion.

3.48 Lebanon needs to carefully review its fuel supply options in light of economic efficiency and energy security. Piped natural gas would be the most economic and environmentally friendly fuel today. If there are barriers to accessing sufficient piped natural gas, due consideration needs to be given to coal and/or continued use of HFO. However, both of these fuels carry some controversy when it comes to environment and economic efficiency, and have implication on technology (both fuels require steam cycle as opposed to CCGT as technology unless these fuels are converted to gas). Manufacturing wise world-wide, the last ten years has seen a significant increase in use of CCGT over Steam Cycle due to increased use of natural gas, but this trend is reversing including in the US. However, as is shown in Graph 3.1 above, CCGT using LNG (at the assumed price of US$11/mmbtu) or continued use of gas-oil, are the least economic options for Lebanon at any load factor.

3.49 The Master Plan should carefully review the options under different price and load factor scenarios. It should also carefully distinguish between base load and peaking capacity requirements. The analysis of demand (see Chapter 2), suggests that the demand expansion pattern in Lebanon shows faster capacity growth (MW) than power generation (GWh) growth. This means that there may be more demand for peak capacity than for base load capacity in the future. This poses a challenge since sufficient generation capacity has to be invested in to meet peak demand which only occurs for a limited period during a 24 hour period and therefore affect overall plant utilization rates. In other words, this type of demand pattern involves significant investment cost but limited revenue generation from the plants since they will not be producing and selling electricity in a base-load mode (i.e., at a lower load factor).

II. INVESTMENT NEEDS AND IMPACT ON PUBLIC SPENDING

3.50 Based on the above measures to increase generation capacity, and a broad estimate of investment needs in distribution, the annual investment needs in the sector are presented in Table 3.7 below. These estimates should be refined and further analyzed in the context of the forthcoming Master Plan.

Table 3.7: Proposed Investment Plan (2007-2015)

US$ million	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	
Generation										
Rehabilitation of Jieh		40.0	60.0							
Rehabilitation of Zouk		40.0	60.0							
New Capacity										
CCGT 1 (450 MW)		80.0	120.0	100.0	80.0					
CCGT 2 (450 MW)					80.0	120.0	100.0	80.0		
Transmission		40.0	40.0	40.0	40.0	40.0				
Distribution										
Remote Metering System		100.0	100.0							
Repairs and Reinforcement		82.7								
Gas Pipeline and/or LNG Facility			125.0	200.0	75.0					
Total	**0.0**	**382.7**	**505.0**	**340.0**	**275.0**	**160.0**	**100.0**	**80.0**	**0.0**	1,842.7

Note: new capacity is assumed to be large CCGT on piped natural gas

Source: World Bank Analysis, Government of Lebanon Public Investment Program (October 2007)

3.51 The above assumes that the required new capacity (1,500 MW of additional capacity) would come from:

- Freed up capacity from loss reduction: 100 MW.
- Rehabilitation of Zouk and Jieh: 130 MW
- The addition of two large CCGTs: 900 MW

- Continued import from Syria: the balance, 300 MW (it is reported that up to 120 MW tends to be operationally available from Syria).

3.52 An additional 70 MW would be required to add up to the total 1,500 MW. The investment needs add up to more than US$1.8 billion over the time period 2007-2015. The Government will need to consider carefully how it can partner with the private sector for some of the investment and which ones would more suitably be undertaken with public funds. The Government's intention is to mobilize private sector investment for new generation and for the distribution network as much as possible. The Government also plans to utilize to the fullest its hydro and renewable energy potential. Chapters 4 and 5 analyze the impact on subsidies to the sector, and attracting the private sector, respectively. Whether the investments are met with public or private financing, the sector cash flow must be restored as a matter of priority.

Chapter 4: Measures to Reduce the Public Expenditures of the Sector

The public expenditures towards the power sector have been concentrated on meeting operating expenditure, primarily fuel as the cost of operating the sector have increased substantially in relation to revenue generation under the current tariff and billing/collection performance. A significant implication as demonstrated in previous chapters has been the deterioration of assets and a further increase in O&M. Several reform measures are being pursued and additional ones have been identified. Implementation of these reforms is critical to halt the continuation of operating subsidies to the sector representing over 3% of GDP. In the best case scenario (Paris III reforms and proposed additional measures), operating subsidies as a % of GDP could be reduced to less than 1% by 2010; in the worst case (no reforms and full funding of required capital investments as well as debt service), subsidies as a % of GDP will remain at or above 4% until 2012.

The reforms will take time and in the meantime, investments are critically needed to prevent further deterioration of existing assets as well as new investment to continue supply of electricity. Meeting the investment needs make the implementation of reforms even more critical, as they will either need public funding support or public support through guarantees to the private sector.

I. Power Sector Expenditures

Introduction

4.1 As presented in Chapter 1, the Government has launched a comprehensive economic reform program in which reform of the energy sector plays a central role. The reforms aim at improving the reliability of electricity supply to support economic growth and reducing the large drain the sector has on public budgetary resources to improve the macro-fiscal position.

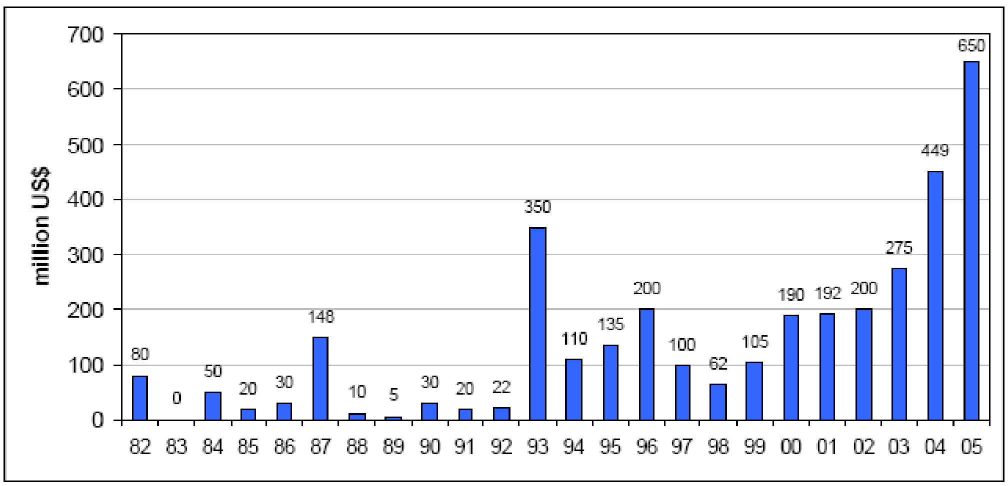
4.2 The electricity sector reform program emphasizes the restructuring of EdL to improve overall management and efficiency; implementation of cost reduction measures through fuel switching; completion of on-going high priority investments and loss reduction; and augmentation of revenues through reduction in illegal consumption of electricity and better collection of bills.

4.3 According to the Electricity Law (Law 462), the Government will privatize the sector over time in order to strengthen incentives to run power utilities efficiently as well as to reduce the need for public sector funding of the sector, both in terms of operating subsidies as well as for investments. The successful privatization of the sector, and the sustainable reduction of fiscal risk, require the implementation of the reform program as well as – once service improves – adjustments in electricity tariffs and the tariff structure to better reflect the cost of service.

Addressing the operating costs of the sector

4.4 With a tariff covering an oil price of only US$25/barrel, and a significant portion of generated electricity remaining unbilled (either due to technical losses or illegal consumption), as well as overall inefficient management of the sector, substantial annual subsidy transfers are required from the Government to EdL. Graph 4.1 below shows that subsidies have been required to EdL dating back as long as 1982, but with a substantial increase in recent years as the international oil prices have increased. Tariff adjustments to compensate for the increased cost have become commercially and politically challenging as the electricity service reliability remain a key issue, with outages occurring throughout Lebanon daily.

Graph 4.1: Subsidies to EdL (1982-2005)



Source: MEW.

4.5 With the deficit of the sector reported to have reached US$758 million before debt service in 2006[45] and estimated to be even higher in 2007 as the international oil price has continued to increase, sector and government resources have been concentrated towards covering operating expenses and new investment in generation capacity or transmission and distribution has not been undertaken (beyond a few already approved projects which are yet to be completed).

4.6 The cost structure of EdL comprises fuel, power purchases, wages, O&M and other administrative costs. The table below illustrates these components' share of the total costs.

Operating cost	**Amount (USD millions)**	**% of total operating cost**
Fuel	1,095.4	83.3%
Power Purchased	117.5	8.9%
Wages	58.8	4.5%
O&M	12.4	0.9%
Other	31.5	2.4%
Total	**1,315.6**	**100%**

Source: RIDPL Program Document, July 9, 2007. Figures are based on 2006 data.

[45] Ministry of Finance, 2007 (LL1,137 billion).

4.7 The Government's reform program therefore rightly seeks to reduce the cost of EdL by switching the fuel used in the combined cycle power plants from gas-oil to natural gas and increasing the revenue through increased billing and cash collection. Overall inefficiencies resulting from the management of EdL and the lack of strategic focus will be addressed through restructuring and eventually privatization of the sector.

4.8 The Government's Paris III Reform Program is being supported by the World Bank through the Reform Implementation Development Policy Loan (RIDPL) which was approved by the World Bank in August, 2007. Several other donors are also supporting the reform program with budgetary support, notably the US and French Governments.

4.9 A fiscal analysis undertaken for the purpose of the RIDPL shows that the Paris III energy reforms will bring substantial savings over time, but that it will take time to completely eliminate the budgetary subsidies to the EdL.

II. REDUCTION OF EXPENDITURES THROUGH REFORMS

Summary of the fiscal analysis of energy sector reforms under Paris III

4.10 The fiscal impact from the Paris III energy reform package is presented in Table 4.1 below, and includes:

- Additional revenue of US$82 million per year by 2012 from reduced illegal consumption;
- Savings of US$208 million as of mid-2008 and full savings of around US$350 million per year from 2009 and onwards from the fuel conversion at the Beddawi power plant; and
- Savings reaching over US$80 million per year by 2012 from the reduction in technical losses and optimization of the grid.

Table 4.1. Subsidy savings and requirements under Paris III energy reforms

Reform Scenario - High Oil Prices & Action Plan

	2007	2008	2009	2010	2011	2012	2013	2014	2015
Revenues									
Revenues									
Sales HV	156.7	168.1	180.6	195.0	210.6	227.5	245.8	265.4	286.7
Sales LV	260.6	279.5	300.2	324.2	350.2	378.3	408.6	441.3	476.7
Improved billing	0.0	7.3	23.0	48.7	68.8	81.9	86.8	91.9	97.3
Capacity charges									
Capacity	53.6	55.2	56.3	57.4	58.5	59.7	60.9	62.1	63.4
Services	3.4	3.5	3.5	3.6	3.7	3.8	3.8	3.9	4.0
Other	61.0	62.8	64.1	65.4	66.7	68.0	69.4	70.8	72.2
Financial revenues	4.4	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.2
Miscellaneous revenues	4.8	4.9	5.0	5.1	5.2	5.4	5.5	5.6	5.7
Total Revenues	**544.5**	**585.8**	**637.3**	**704.2**	**768.6**	**829.5**	**885.7**	**946.1**	**1,011.1**
Expenses									
Fuel	1,145.6	1,480.6	1,462.2	1,511.1	1,590.3	1,678.8	1,704.6	1,760.6	1,817.1
Beddawi conversion to piped gas	0.0	-208.2	-382.9	-370.8	-367.7	-366.2	-346.1	-334.6	-323.0
Transmission & Distribution Network Optimization	0.0	-14.8	-29.2	-45.3	-63.6	-83.9	-85.2	-88.0	-90.9
Power purchase	119.9	123.4	125.9	128.4	131.0	133.6	136.3	139.0	141.8
Wages	59.9	67.9	76.2	83.9	85.6	87.3	89.1	90.8	92.7
O&M	12.7	13.1	13.3	13.6	13.9	14.1	14.4	14.7	15.0
Other	32.1	33.1	33.8	34.4	35.1	35.8	36.5	37.3	38.0
Total Working Expenses	**1,370.2**	**1,495.1**	**1,299.2**	**1,355.4**	**1,424.5**	**1,499.6**	**1,549.6**	**1,619.8**	**1,690.8**
Subsidy before debt service & capital costs	**-825.7**	**-909.3**	**-661.9**	**-651.2**	**-656.0**	**-670.1**	**-663.9**	**-673.7**	**-679.7**

Source: MoF, Edl, and World Bank Staff Calculations

4.11 The detailed assumptions for the analysis are listed in Annex 3 and the main assumptions are summarized in Box 4.1 below for ease of reference:

Box 4.1: Key Assumptions

Power demand: Annual growth rate reaches 5.9% by 2010 and then remains constant.

Fuel prices: Forecast based on IEA's projected crude oil prices per barrel. Diesel price is indexed to the projected price of crude oil per barrel referred above. Heavy fuel oil 1% (HFO 1%) price is also indexed to the projected price of crude oil per barrel referred above. Details of the calculations are provided in Annex 3.

Key Reform Measures Considered:

Three main power reform measures have been considered:

1. **Improved billing**: captures savings from reduced illegal consumption from 17.8% to 8% by 2012 (as a % of total supplied electricity).
2. **Fuel Conversion at Beddawi**: captures savings from switching from gas-oil to Egyptian piped natural gas as of July 1, 2008 at a price of US$5.65/mmbtu.
3. **Transmission and Distribution Network Optimization:** captures a reduction in technical losses from 15% in 2006 to 10% by 2012 from more efficient electricity dispatch in the electric grid and improved billing and collection performance from the tendering underway with the help of CRA.

4.12 Should the reforms fail to be implemented, the subsidy requirements before debt service and capital costs would reach US$1 billion already in 2008 (see Table 4.2 below). This amount would be even greater if oil prices keep going up; above the IEA estimates used in this report.

Table 4.2: Subsidy requirements under a no-reform scenario

Base Case Scenario - High Oil Prices & No Action Plan

US$ millions			**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Revenues											
	Revenues										
		Sales HV	156.7	168.1	180.6	195.0	210.6	227.5	245.8	265.4	286.7
		Sales LV	260.6	279.5	300.2	324.2	350.2	378.3	408.6	441.3	476.7
	Capacity charges										
		Capacity	53.6	55.2	56.3	57.4	58.5	59.7	60.9	62.1	63.4
		Services	3.4	3.5	3.5	3.6	3.7	3.8	3.8	3.9	4.0
		Other	61.0	62.8	64.1	65.4	66.7	68.0	69.4	70.8	72.2
	Financial revenues		4.4	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.2
	Miscellaneous revenues		4.8	4.9	5.0	5.1	5.2	5.4	5.5	5.6	5.7
Total Revenues			**544.5**	**578.5**	**614.3**	**655.5**	**699.8**	**747.5**	**798.9**	**854.2**	**913.8**
Expenses											
	Fuel		1,145.6	1,480.6	1,462.2	1,511.1	1,590.3	1,678.8	1,704.6	1,760.6	1,817.1
	Power purchase		119.9	123.4	125.9	128.4	131.0	133.6	136.3	139.0	141.8
	Wages		59.9	67.9	76.2	83.9	85.6	87.3	89.1	90.8	92.7
	O&M		12.7	13.1	13.3	13.6	13.9	14.1	14.4	14.7	15.0
	Other		32.1	33.1	33.8	34.4	35.1	35.8	36.5	37.3	38.0
Total Working Expenses			**1,370.2**	**1,718.1**	**1,711.4**	**1,771.5**	**1,855.9**	**1,949.7**	**1,981.0**	**2,042.4**	**2,104.6**
Subsidy before debt service & capital costs			**-825.7**	**-1,139.6**	**-1,097.1**	**-1,116.0**	**-1,156.1**	**-1,202.2**	**-1,182.1**	**-1,188.2**	**-1,190.8**

4.13 The electricity sector reform plan under Paris III could reduce the government subsidies substantially from 3.3% of GDP in 2006 and estimated at 3.5% in 2007 (before debt service and capital investment) to 2.0% by 2013. Should however, reforms fail to be implemented, the subsidy requirement will represent 3.3%-4.5% of GDP over the next eight years (see Table 4.3 below). The calculations are based on the oil price assumptions provided in Box 4.1.

Table 4.3: Comparison between action and no action on reforms under High oil prices, in % of GDP

Subsidy before debt service & capital costs (as % of GDP)	2007	2008	2009	2010	2011	2012	2013	2014	2015
With Action Plan	3.5%	3.6%	2.5%	2.3%	2.2%	2.1%	2.0%	1.9%	1.9%
Without Action Plan	3.5%	4.5%	4.1%	3.9%	3.8%	3.8%	3.6%	3.4%	3.3%
GDP Point Opportunity Loss	**0.0%**	**0.9%**	**1.6%**	**1.6%**	**1.7%**	**1.7%**	**1.6%**	**1.5%**	**1.4%**

Source: MoF, EdL, and World Bank Staff Calculations. The subsidy figures exclude debt service and capital costs.

<u>Additional Measures that should be considered to reduce the public expenditures further</u>

4.14 This review has identified a number of additional measures that could and should be considered to reduce the expenditures in the sector. Some of these measures are already under consideration by the Government. The additional measures are:

- Revision of fuel specifications;
- Rehabilitation of the Zouk and Jieh power plants;
- Private operation of the Zouk and Jieh power plants (in parallel to their rehabilitation), as well as the Baalbeck and Tyre power plants;
- Revision of the terms of sales of electricity to concessions;
- Better fuel chain surveillance; and
- Fuel conversion (from gas-oil to Liquefied Natural Gas, LNG) at the second combined cycle gas turbine (CCGT) power plant, Zahrani.

4.15 Implementation of these additional reforms (see Table 4.4) could reduce the energy subsidies to below 1% of GDP (or US$255 million) by 2010.

Table 4.4: Potential fiscal savings from additional measures, US$ millions

Additional Measures	2007	2008	2009	2010	2011	2012	2013	2014	2015
1. Revision of Heavy Fuel Oil Specifications	0.0	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
2. Rehabilitation of Zouk & Jieh	0.0	0.0	0.0	59.8	59.5	59.4	57.5	56.5	55.4
3. Private operation of Zouk & Jieh (& Baalbeck & Tyr)	0.0	-8.0	19.7	19.0	18.8	18.8	17.7	17.0	16.4
4. Revision of terms of sales to concessions	0.0	19.5	30.8	32.6	34.5	36.5	38.7	40.9	43.4
5. Improved Fuel Chain Surveillance	-1.0	73.0	72.1	74.6	78.5	82.9	84.2	87.0	89.9
6. Zahrani Conversion to LNG	0.0	0.0	0.0	198.4	195.3	193.8	173.7	162.2	150.6
Total Additional Savings on Subsidy	**-1.0**	**96.2**	**134.2**	**396.0**	**398.4**	**403.1**	**383.5**	**375.3**	**367.3**
Total Subsidy before Debt Service & Capital Costs	-826.7	-813.1	-527.7	-255.2	-257.6	-267.0	-280.4	-298.4	-312.3
Subsidy as % of projected GDP	**3.5%**	**3.2%**	**2.0%**	**0.9%**	**0.9%**	**0.8%**	**0.8%**	**0.9%**	**0.9%**

4.16 The detailed assumptions for these measures are presented in Annex 3 and are summarized in Box 4.2 below.

Box 4.2: Key Assumptions of Additional Measures

5 **Revision of the fuel specification** on HFO from 1% to 3.5% sulfur content[46] could bring annual savings of close to US$12 million by 2008, through a 5% annual cost saving on the procurement of HFO (based on the difference in prices observed between these two fuels over the first ten months of 2007[47]). A careful analysis of the environmental and health consequences of any change in the fuel specifications should be carried out before implementing this cost-reduction measure.

6 **Rehabilitation of the Jieh and Zouk power plants** could bring annual savings of around US$60 million by 2010, through a reduction in fuel consumption (due to 18.4% and 11.4% fuel efficiency gains of Jieh and Zouk, respectively[48]) and increased revenues from the capture of a portion of large consumers whose demand can now be met due to the improved capacity, net of the additional maintenance costs associated with the rehabilitated plants.

7 **Private operation of Jieh and Zouk, as well as of Baalbeck and Tyre,** could increase efficiency in the operation of the plants and yield savings of up to close to US$20 million per year, based on a 5% reduction in fuel use and net of an average annual private management cost of US$2 million per plant.

8 **Revision of the terms and conditions of sales of electricity sales to concessions** could reduce the sector cost by a further US$43.4 million by 2015 by decreasing the concessionaire's profit margin from 5US¢/kWh to 2US¢/kWh in 2009. The legal implications of this revision need to be assessed.

9 **Improved fuel chain surveillance** of both fuel - and gas-oil could bring savings of US$90 million by 2015 based on a 5% annual reduction in fuel cost (net of surveillance costs).

10 **Fuel conversion at Zahrani** from gas-oil to LNG by 2010 could yield annual savings of close to US$200 million (at an LNG price of US$11/mmbtu) to even greater (at an LNG price of US$8.85/mmbtu) net of the LNG facility investment cost.

III. IMPACT ON GDP FROM INLCUDING THE COST OF THE PUBLIC INVESTMENT PROGRAM AND DEBT SERVICE

4.17 So far in this report the analyses on public expenditures have excluded debt service and capital costs. The Government is currently formulating a Public Investment Program (PIP) in order to prioritize and allocate resources, including Paris III pledges. Based on the October 2007 draft PIP presented by the Government during the IMF/World Bank Annual Meetings in Washington, DC, additional public support is envisaged to the transmission network. Whereas, beyond finalizing existing projects, investment in new generation and in distribution should be mobilized from the private sector to the greatest extent possible. However, any private sector investment in generation and/or distribution would require guarantees by the Government to the private investor so that it would be able to recover its investment in addition to a reasonable

[46] The 1% sulfur content required on HFO used in Lebanese power plants seems inordinately restrictive and has limited supplier markets thus making it more expensive.

[47] Data source: World Bank, Development Economics Vice-Presidency (DEC), December 2007.

[48] These efficiency gains are based on the 22.9% and 14.3% efficiency gains for Jieh and Zouk respectively, as reported in Chapter 3. A 20% discount rate has been applied to reflect a more realistic plant performance after rehabilitation (equivalent to actual consumptions of 255.2 gr/kWh and 220.2 gr/kWh for Jieh and Zouk, respectively).

return. This contingent liability (where the Government is either guaranteeing EdL to pay or several consumers) would essentially replace capital expenditures should the investments be undertaken by the public sector and take the form of an operating expenditure to the Government.

4.18 Chapter 5 analyses the public expenditure implications of a private vs. public generation investment (under a set of assumptions). In this chapter - and to assess the impact on public expenditures - a scenario has been analyzed whereby all investment presented in the proposed investment plan in the previous chapter are undertaken by the public sector to assess the impact on the Government budget. Table 4.5 presents the subsidies required to publicly finance the investments, under three scenarios: (i) where no reforms are implemented; (ii) where the PIP is implemented under a reform scenario that includes the Paris III reforms; and (iii) where the proposed additional measures discussed earlier are carried out on top of the Paris III energy reforms. As mentioned above, even if private sector funds are mobilized to meet the investment needs (in generation and distribution), Government guarantees would be required which are likely to be called given the limited financial ability by EdL to meet the payment obligations to private operators/investors.

4.19 Under these scenarios, the subsidy requirement as a percentage of GDP may exceed 5% by 2008.

Table 4.5: Impact from adding Debt Service and Investment Program, US$ millions

Impact of Investment Plan	2007	2008	2009	2010	2011	2012	2013	2014	2015
I. No Action Scenario									
Subsidy before Debt Service & Capital Cost	-825.7	-1,139.6	-1,097.1	-1,116.0	-1,156.1	-1,202.2	-1,182.1	-1,188.2	-1,190.8
Capital Costs									
Debt Service	-194.0	-73.8	-67.4	-45.6	-37.3	-72.0	-58.6	-40.8	-26.3
Total Subsidy	**-1,019.8**	**-1,213.4**	**-1,164.5**	**-1,161.6**	**-1,193.3**	**-1,274.2**	**-1,240.7**	**-1,229.0**	**-1,217.1**
Subsidy as % of projected GDP	*4.3%*	*4.8%*	*4.4%*	*4.1%*	*4.0%*	*4.0%*	*3.7%*	*3.5%*	*3.3%*
II. Paris III Reform Scenario									
Subsidy before Debt Service & Capital Cost	-825.7	-909.3	-661.9	-651.2	-656.0	-670.1	-663.9	-673.7	-679.7
Capital Costs	0.0	-382.7	-505.0	-340.0	-275.0	-160.0	-100.0	-80.0	0.0
Debt Service	-194.0	-73.8	-67.4	-45.6	-37.3	-72.0	-58.6	-40.8	-26.3
Total Subsidy	**-1,019.8**	**-1,365.8**	**-1,234.4**	**-1,036.8**	**-968.2**	**-902.1**	**-822.6**	**-794.5**	**-705.9**
Subsidy as % of projected GDP	*4.3%*	*5.4%*	*4.6%*	*3.6%*	*3.2%*	*2.9%*	*2.5%*	*2.3%*	*1.9%*
III. Reform Scenario + Additional measures									
Subsidy before Debt Service & Capital Cost	-826.7	-813.1	-527.7	-255.2	-257.6	-267.0	-280.4	-298.4	-312.3
Capital Costs	0.0	-382.7	-505.0	-340.0	-275.0	-160.0	-100.0	-80.0	0.0
Debt Service	-194.0	-73.8	-67.4	-45.6	-37.3	-72.0	-58.6	-40.8	-26.3
Subsidy before Debt Service	**-1,020.8**	**-1,269.6**	**-1,100.1**	**-640.8**	**-569.9**	**-499.0**	**-439.1**	**-419.2**	**-338.6**
Subsidy as % of projected GDP	*4.3%*	*5.1%*	*4.1%*	*2.2%*	*1.9%*	*1.6%*	*1.3%*	*1.2%*	*0.9%*

4.20 The debt service projections used in this analysis are based on Ministry of Finance figures provided to the IMF, while the projected capital costs are imported from the proposed investment plan, presented in Chapter 3 of this Report[49]. It was assumed that under the "No Reform" (No Action) scenario, no new investments would be implemented.

[49] Table 3.7., Page 44.

IV. IMPACT ON ELECTRICITY TARIFFS

4.21 As highlighted in earlier chapters as well as in this chapter, the electricity tariff has not changed since 1996 when the oil price averaged US$21/barrel and has been reported by EdL to cover a US$25/barrel oil price only. The Government recognizes the need to increase the tariff and has engaged consultants to develop an action plan for tariff restructuring (level and structure).

4.22 The impact of tariff increases on subsidy requirements has been analyzed under four scenarios. All of these scenarios were tested under the assumption that the full array of reforms presented earlier in this chapter (Paris III reforms and proposed additional reform measures) could be successfully implemented. The following scenarios were tested:

- **Scenario 1:** A one-off tariff increase in 2010 to break-even before debt service and capital cost. This scenario shows that a 39.5% average tariff increase would be necessary to remove any needs for government subsidy to cover the sector's operating costs (before debt service and capital costs) by 2010.
- **Scenario 2:** A one-off tariff increase in 2010 to break-even after debt service and capital cost. This scenario shows that a 99.2% average tariff increase would be required to cancel out any needs for government subsidy to the sector by 2010.
- **Scenario 3:** A series of smaller and gradual tariff increases, representing a cumulated tariff increase equivalent to Scenario 1 (39.5%), spread over time (2009-2011) to reach break-even before debt service and capital cost. This scenario shows that average annual tariff increases of 12% (in 2009 and 2010) and 11.25% (in 2011), respectively, would be required to remove the need for government subsidy to cover the sector's operating costs (before debt service and capital costs) by 2011 and overall expenditure (including debt service and capital costs) by 2015.
- **Scenario 4:** a series of larger but still gradual tariff increases, representing a cumulated tariff increase equivalent to Scenario 2 (about 99.2%), spread over time (2009-2011) to reach break-even after debt service and capital cost. This scenario shows that average annual tariff increases of 26.5% (in 2009 and 2010) and 24.5% (in 2011) would be required to remove the need for government subsidy to cover the sector's operating costs (before debt service and capital costs) by 2010 and to the overall expenditure (including debt service and capital costs) by 2011.

4.23 Full details of the impact of the tariff increases analyzed under these four scenarios can be found in the tables below (Tables 4.6.A, B, C and D). As illustrated in these tables, the impact of the tariff varies greatly depending on the success of implementing the reforms and whether the PIP is fully funded.

Table 4.6.A. Impact of tariff increase under Scenario 1

Impact of Tariff Increase on Needed Subsidy	2007	2008	2009	2010	2011	2012	2013	2014	2015
Assumption: Real Annual Tariff Increase	**0.0%**	**0.0%**	**0.0%**	**39.5%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
I. Needed Subsidy before Debt Service & Capital Cost									
No Reform Scenario (No increase)	825.7	1,139.6	1,097.1	1,116.0	1,156.1	1,202.2	1,182.1	1,188.2	1,190.8
No Reform Scenario (With increase)	**825.7**	**1,139.6**	**1,097.1**	**860.8**	**883.4**	**910.7**	**870.4**	**854.7**	**833.9**
Paris III Reform Scenario (No increase)	825.7	909.3	661.9	651.2	656.0	670.1	663.9	673.7	679.7
Paris III Reform Scenario (With increase)	**825.7**	**909.3**	**661.9**	**396.0**	**383.3**	**378.6**	**352.3**	**340.2**	**322.7**
Reform Scenario + Additional Measures (No increase)	826.7	813.1	527.7	244.0	246.4	255.9	269.7	287.9	302.2
Reform Scenario + Additional Measures (With incr	**826.7**	**813.1**	**527.7**	**0.0**	**-15.1**	**-24.4**	**-31.2**	**-35.1**	**-44.6**
II. Needed Subsidy before Debt Service									
No Reform Scenario (No increase)	825.7	1,139.6	1,097.1	1,116.0	1,156.1	1,202.2	1,182.1	1,188.2	1,190.8
No Reform Scenario (With increase)	**825.7**	**1,139.6**	**1,097.1**	**860.8**	**883.4**	**910.7**	**870.4**	**854.7**	**833.9**
Paris III Reform Scenario (No increase)	825.7	1,292.0	1,166.9	991.2	931.0	830.1	763.9	753.7	679.7
Paris III Reform Scenario (With increase)	**825.7**	**1,292.0**	**1,166.9**	**736.0**	**658.3**	**538.6**	**452.3**	**420.2**	**322.7**
Reform Scenario + Additional Measures (No increase)	826.7	1,195.8	1,032.7	584.0	521.4	415.9	369.7	367.9	302.2
Reform Scenario + Additional Measures (With incr	**826.7**	**1,195.8**	**1,032.7**	**340.0**	**259.9**	**135.6**	**68.8**	**44.9**	**-44.6**
III. Needed Total Subsidy (including debt service & capital cost)									
No Reform Scenario (No increase)	1,019.8	1,213.4	1,164.5	1,161.6	1,193.3	1,274.2	1,240.7	1,229.0	1,217.1
No Reform Scenario (With increase)	**1,019.8**	**1,213.4**	**1,164.5**	**906.4**	**920.7**	**982.7**	**929.0**	**895.5**	**860.2**
Paris III Reform Scenario (No increase)	1,019.8	1,365.8	1,234.4	1,036.8	968.2	902.1	822.6	794.5	705.9
Paris III Reform Scenario (With increase)	**1,019.8**	**1,365.8**	**1,234.4**	**781.6**	**695.6**	**610.7**	**510.9**	**461.1**	**349.0**
Reform Scenario + Additional Measures (No increase)	1,020.8	1,269.6	1,100.1	629.6	558.7	487.9	428.4	408.8	328.4
Reform Scenario + Additional Measures (With incr	**1,020.8**	**1,269.6**	**1,100.1**	**385.6**	**297.2**	**207.6**	**127.4**	**85.7**	**-18.3**

Table 4.6.B.Impact of tariff increase under Scenario 2

Impact of Tariff Increase on Needed Subsidy	2007	2008	2009	2010	2011	2012	2013	2014	2015
Assumption: Real Annual Tariff Increase	**0.0%**	**0.0%**	**0.0%**	**99.3%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
I. Needed Subsidy before Debt Service & Capital Cost									
No Reform Scenario (No increase)	825.7	1,139.6	1,097.1	1,116.0	1,156.1	1,202.2	1,182.1	1,188.2	1,190.8
No Reform Scenario (With increase)	**825.7**	**1,139.6**	**1,097.1**	**475.2**	**471.5**	**470.4**	**399.5**	**350.9**	**294.6**
Paris III Reform Scenario (No increase)	825.7	909.3	661.9	651.2	656.0	670.1	663.9	673.7	679.7
Paris III Reform Scenario (With increase)	**825.7**	**909.3**	**661.9**	**10.4**	**-28.6**	**-61.7**	**-118.6**	**-163.5**	**-216.5**
Reform Scenario + Additional Measures (No increase)	826.7	813.1	527.7	244.0	246.4	255.9	269.7	287.9	302.2
Reform Scenario + Additional Measures (With incr	**826.7**	**813.1**	**527.7**	**-385.6**	**-427.0**	**-464.7**	**-502.1**	**-538.9**	**-583.8**
II. Needed Subsidy before Debt Service									
No Reform Scenario (No increase)	825.7	1,139.6	1,097.1	1,116.0	1,156.1	1,202.2	1,182.1	1,188.2	1,190.8
No Reform Scenario (With increase)	**825.7**	**1,139.6**	**1,097.1**	**475.2**	**471.5**	**470.4**	**399.5**	**350.9**	**294.6**
Paris III Reform Scenario (No increase)	825.7	1,292.0	1,166.9	991.2	931.0	830.1	763.9	753.7	679.7
Paris III Reform Scenario (With increase)	**825.7**	**1,292.0**	**1,166.9**	**350.4**	**246.4**	**98.3**	**-18.6**	**-83.5**	**-216.5**
Reform Scenario + Additional Measures (No increase)	826.7	1,195.8	1,032.7	584.0	521.4	415.9	369.7	367.9	302.2
Reform Scenario + Additional Measures (With incr	**826.7**	**1,195.8**	**1,032.7**	**-45.6**	**-152.0**	**-304.7**	**-402.1**	**-458.9**	**-583.8**
III. Needed Total Subsidy (including debt service & capital cost)									
No Reform Scenario (No increase)	1,019.8	1,213.4	1,164.5	1,161.6	1,193.3	1,274.2	1,240.7	1,229.0	1,217.1
No Reform Scenario (With increase)	**1,019.8**	**1,213.4**	**1,164.5**	**520.8**	**508.7**	**542.4**	**458.1**	**391.7**	**320.9**
Paris III Reform Scenario (No increase)	1,019.8	1,365.8	1,234.4	1,036.8	968.2	902.1	822.6	794.5	705.9
Paris III Reform Scenario (With increase)	**1,019.8**	**1,365.8**	**1,234.4**	**396.0**	**283.6**	**170.4**	**40.0**	**-42.7**	**-190.2**
Reform Scenario + Additional Measures (No increase)	1,020.8	1,269.6	1,100.1	629.6	558.7	487.9	428.4	408.8	328.4
Reform Scenario + Additional Measures (With incr	**1,020.8**	**1,269.6**	**1,100.1**	**0.0**	**-114.7**	**-232.7**	**-343.5**	**-418.1**	**-557.5**

Table 4.6.C. Impact of tariff increases under Scenario 3

Impact of Tariff Increase on Needed Subsidy	2007	2008	2009	2010	2011	2012	2013	2014	2015
Assumption: Real Annual Tariff Increase	**0.0%**	**0.0%**	**12.0%**	**12.0%**	**11.3%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
I. Needed Subsidy before Debt Service & Capital Cost									
No Reform Scenario (No increase)	825.7	1,139.6	1,097.1	1,116.0	1,156.1	1,202.2	1,182.1	1,188.2	1,190.8
No Reform Scenario (With increase)	**825.7**	**1,139.6**	**1,024.5**	**951.7**	**883.2**	**910.5**	**870.2**	**854.5**	**833.7**
Paris III Reform Scenario (No increase)	825.7	909.3	661.9	651.2	656.0	670.1	663.9	673.7	679.7
Paris III Reform Scenario (With increase)	**825.7**	**909.3**	**589.4**	**486.9**	**383.1**	**378.5**	**352.1**	**340.1**	**322.5**
Reform Scenario + Additional Measures (No increase)	826.7	813.1	527.7	244.0	246.4	255.9	269.7	287.9	302.2
Reform Scenario + Additional Measures (With incr	**826.7**	**813.1**	**455.1**	**91.0**	**-15.2**	**-24.6**	**-31.4**	**-35.3**	**-44.8**
II. Needed Subsidy before Debt Service									
No Reform Scenario (No increase)	825.7	1,139.6	1,097.1	1,116.0	1,156.1	1,202.2	1,182.1	1,188.2	1,190.8
No Reform Scenario (With increase)	**825.7**	**1,139.6**	**1,024.5**	**951.7**	**883.2**	**910.5**	**870.2**	**854.5**	**833.7**
Paris III Reform Scenario (No increase)	825.7	1,292.0	1,166.9	991.2	931.0	830.1	763.9	753.7	679.7
Paris III Reform Scenario (With increase)	**825.7**	**1,292.0**	**1,094.4**	**826.9**	**658.1**	**538.5**	**452.1**	**420.1**	**322.5**
Reform Scenario + Additional Measures (No increase)	826.7	1,195.8	1,032.7	584.0	521.4	415.9	369.7	367.9	302.2
Reform Scenario + Additional Measures (With incr	**826.7**	**1,195.8**	**960.1**	**431.0**	**259.8**	**135.4**	**68.6**	**44.7**	**-44.8**
III. Needed Total Subsidy (including debt service & capital cost)									
No Reform Scenario (No increase)	1,019.8	1,213.4	1,164.5	1,161.6	1,193.3	1,274.2	1,240.7	1,229.0	1,217.1
No Reform Scenario (With increase)	**1,019.8**	**1,213.4**	**1,092.0**	**997.4**	**920.5**	**982.6**	**928.8**	**895.3**	**860.0**
Paris III Reform Scenario (No increase)	1,019.8	1,365.8	1,234.4	1,036.8	968.2	902.1	822.6	794.5	705.9
Paris III Reform Scenario (With increase)	**1,019.8**	**1,365.8**	**1,161.8**	**872.6**	**695.4**	**610.5**	**510.7**	**460.9**	**348.8**
Reform Scenario + Additional Measures (No increase)	1,020.8	1,269.6	1,100.1	629.6	558.7	487.9	428.4	408.8	328.4
Reform Scenario + Additional Measures (With incr	**1,020.8**	**1,269.6**	**1,027.6**	**476.6**	**297.1**	**207.4**	**127.2**	**85.5**	**-18.5**

Table 4.6.D: Impact of tariff increases under Scenario 4

Impact of Tariff Increase on Needed Subsidy	2007	2008	2009	2010	2011	2012	2013	2014	2015
Assumption: Real Annual Tariff Increase	**0.0%**	**0.0%**	**26.5%**	**26.5%**	**24.5%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
I. Needed Subsidy before Debt Service & Capital Cost									
No Reform Scenario (No increase)	825.7	1,139.6	1,097.1	1,116.0	1,156.1	1,202.2	1,182.1	1,188.2	1,190.8
No Reform Scenario (With increase)	**825.7**	**1,139.6**	**936.9**	**728.5**	**471.6**	**470.6**	**399.7**	**351.1**	**294.8**
Paris III Reform Scenario (No increase)	825.7	909.3	661.9	651.2	656.0	670.1	663.9	673.7	679.7
Paris III Reform Scenario (With increase)	**825.7**	**909.3**	**501.7**	**263.7**	**-28.5**	**-61.5**	**-118.4**	**-163.3**	**-216.3**
Reform Scenario + Additional Measures (No increase)	826.7	813.1	527.7	244.0	246.4	255.9	269.7	287.9	302.2
Reform Scenario + Additional Measures (With incr	**826.7**	**813.1**	**367.5**	**-132.3**	**-426.9**	**-464.6**	**-501.9**	**-538.7**	**-583.6**
II. Needed Subsidy before Debt Service									
No Reform Scenario (No increase)	825.7	1,139.6	1,097.1	1,116.0	1,156.1	1,202.2	1,182.1	1,188.2	1,190.8
No Reform Scenario (With increase)	**825.7**	**1,139.6**	**936.9**	**728.5**	**471.6**	**470.6**	**399.7**	**351.1**	**294.8**
Paris III Reform Scenario (No increase)	825.7	1,292.0	1,166.9	991.2	931.0	830.1	763.9	753.7	679.7
Paris III Reform Scenario (With increase)	**825.7**	**1,292.0**	**1,006.7**	**603.7**	**246.5**	**98.5**	**-18.4**	**-83.3**	**-216.3**
Reform Scenario + Additional Measures (No increase)	826.7	1,195.8	1,032.7	584.0	521.4	415.9	369.7	367.9	302.2
Reform Scenario + Additional Measures (With incr	**826.7**	**1,195.8**	**872.5**	**207.7**	**-151.9**	**-304.6**	**-401.9**	**-458.7**	**-583.6**
III. Needed Total Subsidy (including debt service & capital cost)									
No Reform Scenario (No increase)	1,019.8	1,213.4	1,164.5	1,161.6	1,193.3	1,274.2	1,240.7	1,229.0	1,217.1
No Reform Scenario (With increase)	**1,019.8**	**1,213.4**	**1,004.3**	**774.1**	**508.9**	**542.6**	**458.3**	**391.9**	**321.1**
Paris III Reform Scenario (No increase)	1,019.8	1,365.8	1,234.4	1,036.8	968.2	902.1	822.6	794.5	705.9
Paris III Reform Scenario (With increase)	**1,019.8**	**1,365.8**	**1,074.1**	**649.3**	**283.8**	**170.5**	**40.2**	**-42.5**	**-190.0**
Reform Scenario + Additional Measures (No increase)	1,020.8	1,269.6	1,100.1	629.6	558.7	487.9	428.4	408.8	328.4
Reform Scenario + Additional Measures (With incr	**1,020.8**	**1,269.6**	**939.9**	**253.3**	**-114.6**	**-232.5**	**-343.3**	**-417.9**	**-557.3**

Chapter 5: Role of the private sector

The private sector already plays an important role in the operation and maintenance (O&M) of the power sector in Lebanon. This is out of necessity to keep the sector operational as EdL's capacity to manage the sector has reached a critical point. Indeed, it is difficult to envisage how EdL would be able to undertake any major expansion of the sector in its current shape. Therefore, Lebanon must involve the private sector also in the future. The issue, however, is whether it can successfully expand on the current model to include private financing in the short-term and in the absence of comprehensive sector reforms. Financing of the sector is obviously viewed as much riskier by the private sector than is management because of the massive financial deficit in the sector. Because of this high level of risk, the private sector will face a cost of capital above the cost of sovereign debt, and this report estimates that it will therefore cost the Government – through guarantees or other contingent liabilities to compensate that cost of capital – around US¢ents 1.60/kWh more to produce power under an IPP than under a publicly funded project.

This report does not discourage the undertaking of IPPs, nor does it advocate for public financing of new generation assets. What it does recommend is that the Government carefully evaluates the benefits and costs of private vs. public financing, and consider all options, including a private management scheme (e.g. design, build, operate, DBO) and makes an informed decision. Furthermore, the report recommends against implementation or management of generation projects by the public sector. It also strongly recommends that the Government establishes transparent fiscal accounting of any contractual obligations for power purchase or investment so that it can monitor its exposure and payment obligations over the longer-term.

In short, the private sector is part of the solution but it is not a panacea and should not be a substitute for the long-delayed power sector reform. The private sector without power sector reform will be expensive to the Lebanese tax-payer.

<u>Introduction</u>

5.1 Private sector participation in the power sector can take several different forms and options have to be very closely reviewed and designed in the context of each country's circumstances. It is important to keep in mind that private participation, just as with other reforms, is not an end in itself but contributes to broader goals which rely on economic efficiency and good commercial and technical performance of the power sector.

<u>Private sector participation in the sector to date</u>

5.2 Private sector participation is already occurring in the Lebanese electricity sector through (i) operation and maintenance contracts for the two combined cycle power plants; (ii) concessions for the distribution of electricity in Zahle, Jbeil, Aley and Bhamdoun; and (iii) in the outsourcing of several maintenance activities in EdL through the hiring of contractors. The latter is partly due to a decision by the Council of Ministers in the 1990s to freeze hiring in the public sector. Also, the deteriorated public image of EdL makes it difficult for EdL to recruit and retain competent and motivated managers and staff.

5.3 The participation of the private sector to date has not been implemented as part of an overall privatization strategy for the sector but more as a bridging solution in anticipation of sector restructuring and has not involved any substantial private sector financing. The Paris III Reform Program presents a growth strategy based on a much greater role by the private sector as a source of financing. In the electricity sector this includes plans for broader private sector participation in the distribution segment through concessions on the maintenance of the physical network as well as the billing and collection function (including upgrading/replacement of meters). Tendering for this is currently underway. In generation, the Government is seeking private interest in the privatization of the Beddawi power plant and the construction of a new power plant on an IPP basis[50]. The MOEW is also reported to have recently signed Memorandums of Understanding (MoUs) with four companies to construct 60 MW of new capacity (based on diesel oil, natural gas or coal, wind)[51]. The Government's policy for private sector participation in the electricity sector has its legal basis in the Electricity Law of 2002 which allows for the sale of up to 40% of the shares in generation and distribution segments. While the transmission segment would remain in public ownership it could be under private management.

5.4 Increasing the role of the private sector in the sector is a key part of the Government's plan to reduce the need for public sector funding of new investment as well as continued operating subsidies. The private sector is also expected to improve the efficiency of the power sector which today suffers from lack of technical and managerial capacity, political interference and under-staffing and/or lack of up-to-date skills and incentives.

Potential areas for private sector involvement

5.5 Ultimately, the Government plans to privatize EdL - following its restructuring and commercialization. The restructuring work has started with advisors having been contracted to corporatize EdL. Specialized consultants have also been contracted to assist the restructuring process from within EdL and to help improve its commercial and technical performance. However, the Government realizes that the privatization of EdL may take some time given the time and major effort it will take to reduce substantially the subsidy requirements to EdL as presented in Chapter 4.

5.6 Indeed, international experience shows that in situations where very large government subsidies are required, the value of the sector to a potential private investor is very low, if not negative, because of major uncertainty that the subsidies would continue to be adequate after private investment has taken place. If substantial tariff increases are included in the privatization deal to offset that uncertainty, then there is a major risk of a political backlash. If the government has to give substantial guarantees to compensate the tariff and subsidy risks, the

[50] The latter is assisted by IFC's advisory services.
[51] Source: MOF.

resulting contingent liability offsets (at least partially) the fiscal savings from switching to private investment. To attempt to make certain activities profitable through sector un-bundling and the remaining sector maintaining a negative financial position, the effect of the sale of the profitable activities could be an increase in the subsidy requirements (because the positive cash flow that would have to be guaranteed to be paid to the private investors would have to be added to the existing deficit).

5.7 International experience also shows that while the private sector can bring management expertise and also financing to the sector, these two contributions do not always come as part of the same transaction. Firstly, the institutional requirements and pre-requisites to attract the private sector for its management or financing capabilities are significantly different. Attracting private management requires commercial independence of the power sector entities, whereas private investment requires independence and power sector creditworthiness.

5.8 Given that Lebanon is faced with both a lack of independence and a creditworthiness challenge, the focus in the short to medium term is to turn sector performance around and put in place a more effective sector structure and regulation. In the meantime – and in order to facilitate the turnaround of the sector – private sector participation will be deepened in the distribution sector. At the same time, there is a present deficit in generation capacity which needs to be addressed. The Government is keen to attempt to have it developed and financed by the private sector. It is evident that with the lack of capacity in the public sector to tender, finance and operate such a large undertaking, the private sector would have to play a role. The sections below outline some issues, and global lessons learned, that the Government may wish to consider.

<u>Private sector participation in generation</u>

5.9 In support of the private sector led investment scheme for the electricity sector laid out by the Government in the Paris III reform program and in its draft PIP, assistance from the IFC has been sought to solicit private sector interest in new generation under an IPP arrangement and possibly privatization of the Beddawi CCGT. The section below presents the potential expenditure implications for the Government of an IPP under a set of assumptions as well as potential risks that would have to be managed.

5.10 Generally, an IPP approach has the advantage to stimulate competition for entry in the market (if transparently tendered). Tendering is normally based on the lowest cost per kilowatt hour and the incumbent power company agrees to purchase the electricity generated against an agreed tariff under a long term Power Purchase Agreement (PPA). The agreement is generally entered into between the IPP developer and the national power company (typically the transmission company or system operator if unbundled). When the credit standing of the buyer is weak, as is the case in Lebanon, a government guarantee backing the payment obligations of the power company is usually required (the guarantee places the financial obligation on the Government equivalent to a direct sovereign loan to the Government). These agreements are characterized by "take or pay" contracts (i.e., an obligation to pay for a certain amount of electricity regardless of consumption). Box 5.1 below summarizes the three most common ownership structures in private sector participation in the power sector.

Box 5.1: Common Ownership Models for Private Power

BOO – Build-Own-Operate – This common technique calls for an investor to take responsibility, on an indefinite basis, for construction, ownership, and operation of the project. It is normally initiated by a contract for the output of the power plant. Also known as the perpetual franchise model, the Build-Own-Operate model entails a private entity building, financing and operating the project under a perpetual franchise from the host government. The project developer retains title to the assets. Within this model, all financial support for project-related borrowings is provided by the private entity. The government regulates safety, quality of service and, possibly, user charges or profits. The perpetual franchise model can accommodate financing in the public securities market. However, in view of the innovative nature of many projects and the attendant economic risks, the public securities markets, both for debt and equity, will usually be available only after a project has operated successfully for a few years and has established an acceptable record of profitability.

BOT or BOOT – Build-Own-Operate-Transfer – This scheme is similar to BOO but has a future transfer of ownership to a designee, typically the government. The future transfer can be very important where a project has unique characteristics that preclude permanent private ownership, such as hydroelectric power stations. The private entity receives a franchise to finance, build and operate the project for a fixed period of time, after which ownership reverts to the host government (or some local or regional public authority administered by the host government). Ownership reversion is planned to occur only after the private sector entity receive the repayment of, and a satisfactory return on, the capital it has invested in the project. In return for the ownership reversion, the host government might be asked to furnish some limited credit support for project borrowings. The BOT structure is attractive to the host government because of the ownership reversion feature.

BTO – Build-Transfer-Operate – This scheme is used in jurisdictions where private ownership is not permissible, but private operation is desirable. A private entity designs, finances, and builds the project. The entity then transfers the legal title to the host government (or some local or regional public authority) immediately after the project facility passes its completion tests. The private entity then leases the project facility back from the public authority for a fixed term. A long-term lease agreement gives the private entity the right to operate the project facility and to collect revenues for its own account during the term of the lease. At the end of the lease term, the public authority operates the project facility itself or hires someone else (possibly the private entity originally involved) to operate it. Under this model, the host government or public authority has, at most, only a very limited responsibility for the project's financial obligations; the project company has the principal responsibility.

5.11 In order to compare the cost to the Government from investing in a new power plant using public funds to contracting with a private developer bringing capital for the electricity, the potential costs of each solution have been estimated. This is based on the understanding that the Government is interested in a larger scale CCGT (450 MW) and assuming that natural gas would be available from Egypt at a price of approximately US$5.65/mmbtu.

Table 5.1: Basic Assumptions

Technology	CCGT 450 MW
Fuel	Piped natural gas
Fuel cost	US$5.65/mmbtu
Heat rate	7200 kJ/kWh
Load factor	85%
Efficiency	50%
Capital Cost	US$918/kW

Table 5.2: Comparison of costs of a publicly funded power plant and an IPP

	Public	**Private**
Capital cost[52]	US$918/kW	US$918/kW
IPP working capital		3 months of fuel and maintenance costs
Financing	100% public debt financing from an IFI. Assumed terms: • LIBOR plus 9 bps • 15 years maturity; 5 years grace	Debt/equity share of 70/30 • Maturity of 15 years
Risk premium	-	350 bps above LIBOR[53]
Credit enhancement instrument (e.g., PRG)	-	Required for debt and equity, at a cost of 50 bps
Targeted return on equity	-	20%
Levelized cost (US¢/kWh)	6.58 US¢/kWh	8.19 US¢/kWh

Note: Detailed calculation is presented in Annex 4.

5.12 The levelized cost (i.e., the US¢/kWh averaged over the life of the plant) includes all costs related to the investment and the annual generation cost based on an 85% load factor (i.e., the fuel cost, and the fixed and variable O&M costs). A discount rate of 12% has been applied. It is important to note that this analysis assumes that the private sector would not bring lower capital cost, faster commissioning and more efficient operation (which could also be done under public financing and private management). In other words, this analysis (and Tables 5.1 and 5.2 above) is not a calculation of the net benefits of each alternative expected in reality, but merely an illustration of **one dimension**, the cost of financing and the impact of the difference in financing (equity) and development costs between a private developer and development under a public financing package. While this is obviously a limited way of approaching this complex issue, this

[52] Includes engineering costs comprising 8% of construction costs.
[53] Based on information on cost of recent commercial debt to Lebanon.

dimension is very important given the fiscal situation in Lebanon generally and in the power sector more specifically.

5.13 In the IPP case, some additional costs have been assumed including development costs[54] (8% of capital investment, in line with international experience) and working capital[55] requirements (three months of operating costs, in line with international experience) have been added to capital investment costs (resulting in an installed cost per kW of US$1,069 instead of US$918). It was assumed that the expected return on equity of the private sector is 20%[56] and that the IPP debt to equity ratio be 70/30. The cost of private financing has been estimated as based on US$ LIBOR[57] plus 400 basis point and a guarantee fee of 50 bps. This has been assumed to be constant over a 15 year period in the above calculation, which is of course highly sensitive to change[58]. No depreciation is taken into account for IPPs, instead, the interest charge and repayment have been used as a tax shield for the calculation of the profit tax in lieu of depreciation. It is further assumed that the only tax applied to IPPs will be the profit tax, at an assumed rate of 20% and that no import tax will be applied.

5.14 A sensitivity analysis was carried out assuming that IPP financing was accessible through the Government on IFI terms for 50% of the debt. In this case, the levelized cost of an IPP would decrease to US¢8.05/kWh[59], but indeed, the liability incurred by the government would include not only the contingent liability of the payment guarantee under the PPA, but also half of the debt. The relatively small difference between entirely private financing and 50/50 private-public financing and the significant remaining difference between public sector and private sector levelized cost (US¢6.58/kWh compared to US¢8.05/kWh) is due to the fact that the main difference between the levelized cost under public and private financing is due mainly to the cost of dividend payments (US¢0.88/kWh) and corporate taxes (US¢0.22.kWh).

5.15 The benefit to the Government of an IPP is that the capital cost and O&M costs should be lower than for a public sector project, and the commissioning faster. Also, it is possible,

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[54] IPP specific costs such as due diligence of the lenders under their mandate letters, the costs incurred by the developers during the IPP negotiations and the legal costs for the preparation and negotiation of the contracts and lending arrangements.

[55] Covering the testing and start-up costs for the estimated two and a half months after completion of construction before full commercial generation is achieved and the time lag of a half month between the moment the operating costs for generation are incurred and the time the electricity delivered is paid by the off-taker (no time lag for fuel is included, as the payment for fuel is generally made several weeks after delivery.

[56] The target return on equity of private investors for power projects tend be at least 20% depending on perceived country and operational risk.

[57] December 2007.

[58] No depreciation is taken into account for IPPs, instead, the interest charge and repayment have been used as a tax shield for the calculation of the profit tax in lieu of depreciation. The rationale for this practice is that, in the case of a private plant, at the end of the project period, the plant is not supposed to be renewed by the investor (and depreciation is supposed to cover the equivalent of an allowance to renew the equipment at the end of its technical life), but to be shut down, or fully reconstructed. So the investor is allowed to recover the funds needed to service the project debt, plus their profit, but not to charge for the reconstruction cost

[59] The small difference between entirely private financing and 50/50 private-public finncing and the significant remaining difference between public sector and privae sector levelized cost (USCents 6.58 compared to 8.08) is due to the fact that the main difference between the levelized cost under public and private financing is due mainly to the cost of dividend payments (USCents 0.88/kWh) and corporate taxes (USCents 0.22.kWh), development costs and working apital (USCents 0.29/kWh), whereas the difference in the cost of borrowing is only USCents0.23/kWh.

although not certain, if the PPA includes a fuel cost pass-through clause, that the fuel costs may be lower (if the contract is not an Energy Conversion Agreement; see next section on risks), and the Government will not incur sovereign debt. The Government will, however, incur a contingent liability arising from the payment guarantee required for the duration of the project[60]. This contingent liability appears on the Government balance sheet. Ultimately, the cost to the Government is that the private sector's risk premium will need to be covered by higher tariffs/subsidies and/or guarantees. As an illustration, comparative payment obligations at load factors ranging from 25%-85% have been calculated and are presented below.

Table 5.3: Payment obligations for a 450 MW CCGT (in US$ million)

	Load factor	25%	35%	45%	55%	65%	75%	85%
Public								
	Fixed costs	76.23	76.23	76.23	76.23	76.23	76.23	76.23
	Variable costs	34.92	48.89	62.85	76.82	90.79	104.76	118.72
	Yearly payment	111.15	125.12	139.09	153.05	167.02	180.99	194.96
Private								
	Capacity charge	129.14	129.14	129.14	129.14	129.14	129.14	129.14
	Energy charge	34.92	48.89	62.85	76.82	90.79	104.76	118.72
	Yearly payment	164.06	178.03	191.99	205.96	219.93	233.90	247.86

5.16 Table 5.3 below summarizes the pros and cons of public vs. private financing of new power generation.

Table 5.3: Pros and Cons of Public vs. Private financing, construction and management of new power generation

	Public	**Private**
Pros	Lower payment obligations as a result of lower cost of capital for sovereign debt (and possible availability of concessional element in donor financing).	Efficiency in engineering, procurement and construction.
		Timely availability of the power supply based on contractual agreement.
Cons	Public procurement likely to	Higher payment obligations as

[60] Taking into account EdL's poor financial condition, private developers will require a payment guarantee from the Government for the life of the project. Accounting wise, this guarantee enters the Government's balance sheet as a liability equal to the value of the payments to be made under the PPA.

	take a long time.	a result of high risk premium charged by the private investor.
	No recent experience in the Lebanese public sector of large scale engineering, procurement and supervision of the tendering, construction and operating phase.	

Private sector participation in distribution

5.17 Under a project called “Closing the Financial Gap”, Charles River Associates (CRA) has been hired to assist the Government in addressing losses of revenue in the distribution segment and its overall management and operational inefficiencies. The components of the project are based on the implementation of a Collection Management and Metering (CMM) system through the installation of Automatic Meter Reading (AMR) as well as outsourcing of the distribution services (O&M, construction and other related services). The benefits (essentially from reduced non-technical losses and improved billings) have been estimated by CRA to range from US$140-US$180 million per year. The proposed funding structure is for a Design Build and Operate (DBO) Turnkey Project with funding arranged by the winning bidder or Government loans. The tendering is for two contracts, one to implement the CMM contract and meters and one under a service provider contract to undertake the function of network services. The estimated cost is US$150-US$200 million for the metering hardware, plus interest on financing, the cost of operation of the system and the profit of the entrepreneur.

5.18 International experience shows that in a situation of severe cash shortage in the power sector the creation of autonomous distribution companies could lead to even greater subsidy requirements and more unreliable electricity supply as the distribution companies may keep the cash collected and not allocate it up to transmission and generation where the major expenditure takes place, particularly for fuel purchase. There is also risk that they become political cash cows (i.e., collection of electricity revenues are used to advance political agendas in distribution regions). It is therefore paramount that the proposed schemes with the private sector under the CMM contract ensure sufficient cash-flow for the rest of the sector. This is likely to be a major issue as and when these transactions come to closure: the private investors/developers will be concerned with making sure that they will receive a guaranteed return on investment and may even request that revenue collected is “ring-fenced” for this purpose to their benefit (see more below).

5.19 One option which could be considered in the short to medium term is to expand the role of the private sector through the delegation of management control of EdL. This is already happening on a decentralized basis through the O&M contracts with KELECO and the forthcoming and planned participation of the private sector in the distribution segment. The expansion could be either one or more management contracts, or one or more “affermage” contracts (lease-back) under which the ownership of assets remains with the Government (as their market value is nil or possibly negative at the moment). The development and heavy maintenance of assets could be the financial responsibility of the Government, while the private sector takes the operational and commercial risk. It would be essential that the private sector has effective management control and that the power sector is exempted from political interference in management and operations.

Risks that need to be carefully considered and mitigated to attract the private sector:

5.20 There are several issues and risks that need to be acknowledged and addressed in order to attract and retain the private sector in the power sector in Lebanon. These span from ensuring continued improvement in the operation and supply of electricity in the country to the need for public sector resource allocation in the form of guarantees and continued subsidies. Some issues and risks are exogenous to the sector and some are sector-specific.

5.21 The political risk: This risk is significant with the present political situation generating considerable uncertainty for potential private investors in capital-intensive regulated infrastructure. In the power sector, the linkage between the political cleavage and the capacity to bill for electricity and collect revenue exacerbates the political risk perception by the market. However, discussions with potential investors and lenders suggests that although they are aware of the high level of political risk, they might rather take it into account in the pricing of their financing and expected return rather than consider it as an insurmountable obstacle for their involvement in the power sector, provided the other risks are adequately dealt with. Some indications of the pricing for the political risk were in the order of 400 basis points (bps). The private investors that were approached also indicated that political risk management instruments which can be provided by bilateral or multilateral finance institutions would be useful.

5.22 The credit risk: This is the main issue in the medium term**.** The dire financial situation of the power sector makes it non-creditworthy for potential investors and lenders and dependent on Government subsidies in the medium term. It is obvious that private investors will not be willing to provide financing, as debt or equity, to a sector which is unable to meet its payment obligations and which is unable to service its existing debt without Government financial support. Acknowledging that the power sector is not creditworthy, a possibility would be for the Government to guarantee directly the financial obligations to investors and lenders to the sector mainly in foreign currency. This approach would put the burden of power sector financing on the Government budget in the medium term. Discussions with potential lenders indicated that they may have reservations from the credit stand point regarding a guarantee from the Government, because of (i) their already high exposure to sovereign risk with the Government in other sectors; (ii) the possible impact of higher exposure to Government financial risk on their international credit standing; and (iii) their limited trust in the capacity of the Government to service additional debt in a reliable and timely manner. It is therefore clear that financing for the power sector may not rely alone on the sector creditworthiness, and Government financial strength in the short to medium-term.

5.23 There are several mitigation measures to consider: (i) "ring-fencing" cash flow to the benefit of financiers. Under this measure, the revenues from the sales of power in certain areas where the billing and collection performance is strong (i.e., Beirut) could be captured and paid to investors based on their status as senior lenders. The ring-fenced cash flow would most likely be a multiple of the debt service to cover the macro and commercial risk. This approach may be found acceptable by certain lenders and therefore facilitate successful closure of a transaction, but will further weaken the cash flow of the sector and increase Government payment obligations; (ii) setting-up a significant reserve account to guarantee future debt service. Under this measure, the Government would set-up a reserve account, preferably off-shore and in foreign currency, perhaps using some of the funds pledged by donors for the energy sector at the Paris III Conference to back-stop the payment obligations of the sector and the Government. This approach may be preferable to a guarantee mechanism; to the extent the recourse to the reserve account may be faster and simpler than calling on a guarantee. The benefit of this approach would be that the amounts to be allocated to the reserve account could be smaller than the financing raised on the market, and leverage donor financing. In addition, provided the sector and the Government meet their future payment obligation and the reserve account is not called upon, it may increase the level of confidence of lenders in the power sector; and (iii) Securing financial resources to service future debt service through an international government bond issue and putting the proceeds of the bond issue in a dedicated account. Under this measure, the issuance of bonds seems to be feasible, but the financial cost to the Government would be high.

5.24 The foreign-exchange risk: This is a major risk in the medium term. The concern with the macroeconomic prospects of the Lebanese economy is high amongst potential private investors, reflecting their concern with the impact of future external debt service on the currency. Potential lenders approached recognize that the strong flow of migrant remittances provides some comfort, but expressed their reluctance to take a foreign-exchange risk through lending in local currency and increasing their exposure in Lebanese Pounds. On the other hand, they indicated that, provided other risks are addressed, they would be willing to provide long term financing in foreign currency (essentially in US$ and possibly in Euro). For the power sector, the scarcity of financing in local currency is a challenge, as sector revenues are denominated in local currency, and the sector already has a very high exposure to foreign exchange risk through its dependence on imported fuels priced in US$ as well as significant foreign debt. The mis-match therefore between the revenue currency and the currency of financing of sector investment by the private sector in a context of weak macroeconomic prospects as perceived by lenders is an issue for raising private financing for the power sector. Having said that, a significant share of the sector expenditures will remain to be in foreign currency even in the absence of an IPP since the fuel is paid for in foreign currency. Also, the Lebanese economy is quite dollarized which mitigates to some extent this risk.

5.25 Possible other mitigating measures can be based on the "stripping" of the foreign-exchange risk by distinguishing risks which are related to some extent to the sovereign (e.g., exchange rate, convertibility, transferability), and those which are beyond the control of the sovereign (e.g., international fuel prices): (i) exchange rate risk can be mitigated to some extent through currency swap operations. The foreign exchange risk can also be mitigated by earmarking a small portion of the remittances to guarantee the availability of foreign currency for lenders to the power sector; and (ii) a "Guarantee Fund" could be set-up with the financial support of selected donors to deal specifically with selected risks. In addition special lending instruments with a reverse indexation on selected fuel prices could be used.

5.26 Fuel supply: Fuel procurement is currently undertaken by EdL and paid for by the Government to a large extent since the tariff is set to cover an oil price of only US$25/barrel. A natural gas import agreement has been signed with Egypt for delivery of gas starting in the second half of 2008 and in sufficient volume to fuel additional capacity. This is a government-to-government agreement and is still pending the completion of pipeline infrastructure in Jordan and Syria as well as concluding a gas transit agreement between Egypt and Syria. In this context, a private investor in new generation capacity may prefer, or even insist, on Energy Conversion Agreements (ECAs) instead of a PPA. The substantive difference between these two (as these terms are commonly used in the IPP industry) is that a PPA has a fuel component and an ECA does not. Under an ECA, the investor is responsible for converting provided fuel into electricity and any potential fuel interruption is outside of the responsibility of the investor. It is important to note however that it is not necessary to have a fuel component (as in a PPA) to hold investors responsible for the plant heat rate (i.e., the efficiency of fuel usage). In international experience, PPAs are much more common than ECAs, but ECA are used where fuel supply is under a monopoly and/or the risk of fuel supply is considered to be better managed by the public entities. In any event, all power plants that are constructed in Lebanon should be dual-fired otherwise the non-availability of gas would threaten the sustainability even of an ECA.

5.27 The regulatory risk**:** An additional risk is the present lack of clarity and track record with power sector regulation. The regulation of competition in the generation sector, the uncertainty regarding the specifics of the future structure of the power market, and regarding future price adjustment mechanisms at the wholesale and at the consumer level will need to be clarified to raise private sector financing on a significant scale. In this regard, it is important that the Government finalize the arrangements and establishes the planned Energy Regulatory Authority as soon as possible. The existence of an regulatory agency would also help strengthen the transparency and accountability of power sector regulation and provide sector leadership in events of changes in government and in Energy Ministers in particular.

5.28 The issues raised above are in line with the findings of the privatization plan prepared by BNP Paribas in 2002. In this plan, it was envisaged that Lebanon would be able to attract investors to purchase generation and distribution assets provided: (i) guarantees covering regulatory and public entities' payment risk are in place; (ii) the focus be on the most attractive distribution areas; (iii) protection against currency devaluation risk through pass through of such risk be considered in the tariff to consumers; and (iv) the investor is provided adequate period of exclusivity. Without these structures in place, private sector participation would be limited to alternatives such as concessions, O&M contracts and management contracts.

5.29 Although prospects for raising private sector financing may seem limited, the Government should test the appetite of the market through opening discussions with potential financiers regarding the terms under which they may be willing to provide financing. However, these discussions should be based on an open consultation and negotiation. It is this report's view however that any contract entered into with the private sector, including privatization of segments of the sector, needs to be carefully reviewed as the cost to Lebanon could be considerable and may make the sector deficit even worse before any prospects of improvement. Private sector involvement in the *management* of selected activities in the power sector would need to continue to ensure continued supply of electricity and steady improvement in the commercial aspects of the sector as envisaged in the Government's reform plan for the sector.

ANNEXES

Annex I (Chapter 2)

A. *Details of Demand Assumptions*

Three GDP Growth Scenarios

GDP Growth Scenarios	2008	2009	2010	2011	2012	2013	2014	2015
High Case	4.7%	5.0%	5.0%	5.5%	5.5%	5.5%	5.5%	5.5%
Base case	**3.5%**	**4.5%**	**5.0%**	**5.0%**	**5.0%**	**5.0%**	**5.0%**	**5.0%**
Low Case	2.9%	2.9%	2.9%	2.9%	3.0%	3.0%	3.0%	3.0%

Elasticity Assumptions

Demand Elasticity Assumptions	2008	2009	2010	2011	2012	2013	2014	2015
Price Elasticity	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Income (GDP) Elasticities								
Private LT	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Private HT	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
Government LT	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Concessions	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15

Suppressed demand

Suppressed demand (load shedding) was estimated at 8.8%, based on EdL figures and calculations using known demand in areas where power is shed. Such suppressed demand estimation was evaluated by Chubu in 2002, and confirmed by the World Bank in 2007.

Weight of Self Generation for key demand categories

Estimates of the share of low-voltage demand met by self generation (11%) were based on Chubu study and confirmed to the World Bank by EdL in March 2007.

Estimates of the share of high-voltage demand met by self-generation (67%) were based on Chubu figures (and as confirmed in Lebanon 2006 ICA), which estimated the share of HT consumers relying mainly on self-generation at 80%, as well as World Bank observations that most commercial and residential buildings are equipped with generators. These shares were kept constant over the full period covered by the demand projections.

User Category	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Private LT	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%
Private HT	67.0%	67.0%	67.0%	67.0%	67.0%	67.0%	67.0%	67.0%	67.0%	67.0%
Government LT	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%
Concessions	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%

Base Year (2006) Assumptions

Electricity billed by EdL in 2006

User Category	MWh
Private LT	3,892,278
Private HT	1,273,363
Government LT	252,196
Concessions	925,560
Total	**6,343,397**

Source: EdL, 2007

Electricity distributed by EdL in 2006

User Category	MWh	User Share of Total	% of Total Demand met by EdL
Private LT	4,943,193	61%	81.8%
Private HT	1,617,171	20%	30.3%
Government LT	320,288	4%	81.8%
Concessions	1,175,461	15%	81.8%
Total	**8,056,114**	**100%**	**61.0%**

Source: EdL, 2007

Potential Short-Term Demand to be met by EdL

The potential short-term demand that EdL could be faced with was estimated as the total electricity distributed by EdL (8,056 GWh) increased by the suppressed demand (8.8%), applied evenly for each user category.

User Category	MWh
Private LT	5,378,194
Private HT	1,759,482
Government LT	348,474
Concessions	1,278,902
Total	**8,765,052**

Total Estimated Electricity Demand

The total estimated electricity demand was calculated as the sum of EdL's potential short-term demand and of the estimated total demand met by self generation (11% of Low Voltage demand and 67% of High Voltage demand). Un-served demand is included in EdL's potential Short Term Demand.

User Category	MWh	Share of Total
Private LT	6,042,915	46%
Private HT	5,331,765	40%
Government LT	391,544	3%
Concessions	1,436,968	11%
Total	**13,203,191**	**100%**

B. Details of Demand Projections

Projected Total Demand

In MWh	2006 (actual)	2007	2008	2009	2010	2011	2012	2013	2014	2015
Base case Scenario										
Private LT	6,042,915	6,115,430	6,372,278	6,716,381	7,119,364	7,546,525	7,999,317	8,479,276	8,988,032	9,527,314
Private HT	5,331,765	5,393,080	5,610,151	5,900,477	6,239,754	6,598,540	6,977,956	7,379,189	7,803,492	8,252,193
Government LT	391,544	395,851	411,091	431,440	455,169	480,203	506,614	534,478	563,875	594,888
Concessions	1,436,968	1,453,493	1,511,997	1,590,242	1,681,681	1,778,378	1,880,635	1,988,771	2,103,126	2,224,055
Total	**13,203,191**	**13,357,854**	**13,905,516**	**14,638,540**	**15,495,968**	**16,403,647**	**17,364,522**	**18,381,714**	**19,458,524**	**20,598,450**
Demand Growth Rate		*1.2%*	*4.1%*	*5.3%*	*5.9%*	*5.9%*	*5.9%*	*5.9%*	*5.9%*	*5.9%*
Low case Scenario										
Private LT	6,042,915	6,042,915	6,253,208	6,470,820	6,696,004	6,929,025	7,178,470	7,436,895	7,704,623	7,981,990
Private HT	5,331,765	5,331,765	5,509,579	5,693,323	5,883,196	6,079,400	6,289,140	6,506,115	6,730,576	6,962,781
Government LT	391,544	391,544	404,034	416,923	430,222	443,946	458,597	473,730	489,363	505,512
Concessions	1,436,968	1,436,968	1,484,891	1,534,412	1,585,585	1,638,464	1,694,991	1,753,468	1,813,963	1,876,545
Total	**13,203,191**	**13,203,191**	**13,651,712**	**14,115,478**	**14,595,007**	**15,090,836**	**15,621,198**	**16,170,209**	**16,738,526**	**17,326,828**
Demand Growth Rate		*0.0%*	*3.4%*	*3.4%*	*3.4%*	*3.4%*	*3.5%*	*3.5%*	*3.5%*	*3.5%*
High case Scenario										
Private LT	6,042,915	6,187,945	6,536,945	6,929,161	7,344,911	7,829,675	8,346,434	8,897,298	9,484,520	10,110,498
Private HT	5,331,765	5,454,395	5,749,205	6,079,785	6,429,372	6,836,030	7,268,409	7,728,136	8,216,940	8,736,662
Government LT	391,544	400,158	420,846	443,992	468,412	496,751	526,804	558,676	592,476	628,320
Concessions	1,436,968	1,470,019	1,549,473	1,638,568	1,732,785	1,842,384	1,958,915	2,082,816	2,214,554	2,354,625
Total	**13,203,191**	**13,512,516**	**14,256,469**	**15,091,506**	**15,975,480**	**17,004,840**	**18,100,562**	**19,266,926**	**20,508,490**	**21,830,106**
Demand Growth Rate		*2.3%*	*5.5%*	*5.9%*	*5.9%*	*6.4%*	*6.4%*	*6.4%*	*6.4%*	*6.4%*

Projected Demand Met by Self-Generation

In MWh	2006 (actual)	2007	2008	2009	2010	2011	2012	2013	2014	2015
Base case Scenario										
Private LT	664,721	672,697	700,951	738,802	783,130	830,118	879,925	932,720	988,684	1,048,005
Private HT	3,572,282	3,613,364	3,758,801	3,953,319	4,180,635	4,421,022	4,675,231	4,944,056	5,228,340	5,528,969
Government LT	43,070	43,544	45,220	47,458	50,069	52,822	55,728	58,793	62,026	65,438
Concessions	158,067	159,884	166,320	174,927	184,985	195,622	206,870	218,765	231,344	244,646
Total	**4,438,139**	**4,489,489**	**4,671,292**	**4,914,506**	**5,198,819**	**5,499,584**	**5,817,753**	**6,154,334**	**6,510,393**	**6,887,057**
Demand Growth Rate		*1.2%*	*4.0%*	*5.2%*	*5.8%*	*5.8%*	*5.8%*	*5.8%*	*5.8%*	*5.8%*
Low case Scenario										
Private LT	664,721	664,721	687,853	711,790	736,560	762,193	789,632	818,058	847,509	878,019
Private HT	3,572,282	3,572,282	3,691,418	3,814,527	3,941,741	4,073,198	4,213,724	4,359,097	4,509,486	4,665,063
Government LT	43,070	43,070	44,444	45,861	47,324	48,834	50,446	52,110	53,830	55,606
Concessions	158,067	158,067	163,338	168,785	174,414	180,231	186,449	192,882	199,536	206,420
Total	**4,438,139**	**4,438,139**	**4,587,053**	**4,740,964**	**4,900,040**	**5,064,456**	**5,240,250**	**5,422,147**	**5,610,360**	**5,805,108**
Demand Growth Rate		*0.0%*	*3.4%*	*3.4%*	*3.4%*	*3.4%*	*3.5%*	*3.5%*	*3.5%*	*3.5%*
High case Scenario										
Private LT	664,721	680,674	719,064	762,208	807,940	861,264	918,108	978,703	1,043,297	1,112,155
Private HT	3,572,282	3,654,445	3,851,968	4,073,456	4,307,679	4,580,140	4,869,834	5,177,851	5,505,350	5,853,563
Government LT	43,070	44,017	46,293	48,839	51,525	54,643	57,948	61,454	65,172	69,115
Concessions	158,067	161,702	170,442	180,242	190,606	202,662	215,481	229,110	243,601	259,009
Total	**4,438,139**	**4,540,838**	**4,787,767**	**5,064,745**	**5,357,751**	**5,698,709**	**6,061,371**	**6,447,118**	**6,857,421**	**7,293,842**
Demand Growth Rate		*2.3%*	*5.4%*	*5.8%*	*5.8%*	*6.4%*	*6.4%*	*6.4%*	*6.4%*	*6.4%*

Projected Demand to be Met by the Grid (EdL)

In MWh	2006 (actual)	2007	2008	2009	2010	2011	2012	2013	2014	2015
Base case Scenario										
Private LT	5,378,194	5,442,732	5,671,327	5,977,579	6,336,234	6,716,408	7,119,392	7,546,556	7,999,349	8,479,310
Private HT	1,759,482	1,779,716	1,851,350	1,947,157	2,059,119	2,177,518	2,302,726	2,435,132	2,575,152	2,723,224
Government LT	348,474	352,307	365,871	383,981	405,100	427,381	450,887	475,686	501,848	529,450
Concessions	1,278,902	1,293,609	1,345,677	1,415,316	1,496,696	1,582,756	1,673,765	1,770,006	1,871,782	1,979,409
Total	**8,765,052**	**8,868,365**	**9,234,225**	**9,724,033**	**10,297,149**	**10,904,063**	**11,546,769**	**12,227,380**	**12,948,131**	**13,711,393**
Demand Growth Rate		*1.2%*	*4.1%*	*5.3%*	*5.9%*	*5.9%*	*5.9%*	*5.9%*	*5.9%*	*5.9%*
Low case Scenario										
Private LT	5,378,194	5,378,194	5,565,355	5,759,030	5,959,444	6,166,832	6,388,838	6,618,837	6,857,115	7,103,971
Private HT	1,759,482	1,759,482	1,818,161	1,878,797	1,941,455	2,006,202	2,075,416	2,147,018	2,221,090	2,297,718
Government LT	348,474	348,474	359,590	371,061	382,898	395,112	408,151	421,620	435,533	449,906
Concessions	1,278,902	1,278,902	1,321,553	1,365,627	1,411,171	1,458,233	1,508,542	1,560,587	1,614,427	1,670,125
Total	**8,765,052**	**8,765,052**	**9,064,660**	**9,374,514**	**9,694,967**	**10,026,380**	**10,380,948**	**10,748,061**	**11,128,165**	**11,521,719**
Demand Growth Rate		*0.0%*	*3.4%*	*3.4%*	*3.4%*	*3.4%*	*3.5%*	*3.5%*	*3.5%*	*3.5%*
High case Scenario										
Private LT	5,378,194	5,507,271	5,817,881	6,166,954	6,536,971	6,968,411	7,428,326	7,918,596	8,441,223	8,998,344
Private HT	1,759,482	1,799,950	1,897,238	2,006,329	2,121,693	2,255,890	2,398,575	2,550,285	2,711,590	2,883,098
Government LT	348,474	356,140	374,553	395,153	416,886	442,108	468,856	497,221	527,303	559,205
Concessions	1,278,902	1,308,317	1,379,031	1,458,325	1,542,179	1,639,722	1,743,434	1,853,706	1,970,953	2,095,616
Total	**8,765,052**	**8,971,678**	**9,468,702**	**10,026,761**	**10,617,729**	**11,306,131**	**12,039,191**	**12,819,808**	**13,651,070**	**14,536,263**
Demand Growth Rate		*2.4%*	*5.5%*	*5.9%*	*5.9%*	*6.5%*	*6.5%*	*6.5%*	*6.5%*	*6.5%*

Alternative Analysis - Projected Demand to be Met by the Grid (EdL) if some demand met by Self-Generation was recaptured

Further analysis of the impact of some capture by EdL's grid of demand currently met by self-generation was calculated, under the following modified self-generation assumptions:

Share of demand met by Self-Generation, by user category

User Category	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Private LT	11.0%	11.0%	11.0%	11.0%	10.0%	9.0%	8.0%	8.0%	8.0%	8.0%
Private HT	67.0%	67.0%	67.0%	67.0%	67.0%	65.0%	60.0%	55.0%	55.0%	50.0%
Government LT	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	10.0%	10.0%	9.0%
Concessions	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%

Based on these revised assumptions (and all other assumptions remaining constant), new projected demand to be met by EdL was estimated for the three GDP growth scenarios described earlier (see below).

In MWh	2006 (actual)	2007	2008	2009	2010	2011	2012	2013	2014	2015
Base case Scenario										
Private LT	5,378,194	5,442,732	5,671,327	5,977,579	6,407,427	6,867,338	7,359,372	7,800,934	8,268,990	8,765,129
Private HT	1,759,482	1,779,716	1,851,350	1,947,157	2,059,119	2,309,489	2,791,182	3,320,635	3,511,571	4,126,096
Government LT	348,474	352,307	365,871	383,981	405,100	427,381	450,887	481,030	507,487	541,348
Concessions	1,278,902	1,293,609	1,345,677	1,415,316	1,496,696	1,582,756	1,673,765	1,770,006	1,871,782	1,979,409
Total	**8,765,052**	**8,868,365**	**9,234,225**	**9,724,033**	**10,368,343**	**11,186,964**	**12,275,206**	**13,372,605**	**14,159,830**	**15,411,983**
Demand Growth Rate		*1.2%*	*4.1%*	*5.3%*	*6.6%*	*7.9%*	*9.7%*	*8.9%*	*5.9%*	*8.8%*
Low case Scenario										
Private LT	5,378,194	5,378,194	5,565,355	5,759,030	6,026,404	6,305,413	6,604,193	6,841,943	7,088,253	7,343,431
Private HT	1,759,482	1,759,482	1,818,161	1,878,797	1,941,455	2,127,790	2,515,656	2,927,752	3,028,759	3,481,390
Government LT	348,474	348,474	359,590	371,061	382,898	395,112	408,151	426,357	440,427	460,016
Concessions	1,278,902	1,278,902	1,321,553	1,365,627	1,411,171	1,458,233	1,508,542	1,560,587	1,614,427	1,670,125
Total	**8,765,052**	**8,765,052**	**9,064,660**	**9,374,514**	**9,761,927**	**10,286,549**	**11,036,542**	**11,756,639**	**12,171,867**	**12,954,962**
Demand Growth Rate		*0.0%*	*3.4%*	*3.4%*	*4.1%*	*5.4%*	*7.3%*	*6.5%*	*3.5%*	*6.4%*
High case Scenario										
Private LT	5,378,194	5,507,271	5,817,881	6,166,954	6,610,420	7,125,004	7,678,719	8,185,515	8,725,758	9,301,659
Private HT	1,759,482	1,799,950	1,897,238	2,006,329	2,121,693	2,392,611	2,907,364	3,477,661	3,697,623	4,368,331
Government LT	348,474	356,140	374,553	395,153	416,886	442,108	468,856	502,808	533,228	571,772
Concessions	1,278,902	1,308,317	1,379,031	1,458,325	1,542,179	1,639,722	1,743,434	1,853,706	1,970,953	2,095,616
Total	**8,765,052**	**8,971,678**	**9,468,702**	**10,026,761**	**10,691,178**	**11,599,445**	**12,798,373**	**14,019,690**	**14,927,563**	**16,337,377**
Demand Growth Rate		*2.4%*	*5.5%*	*5.9%*	*6.6%*	*8.5%*	*10.3%*	*9.5%*	*6.5%*	*9.4%*

C. Current Electricity Tariff Structure

EdL Electricity Tariffs - 2006 (per kWh)

Category	LL	US Cents
Low voltage		
0-100 kWh	35	2.33
100-200 kWh	55	3.67
200-300 kWh	55	3.67
300-400 kWh	80	5.33
400-500 kWh	120	8.00
>500 kWh	200	13.33
Public Administration	140	9.33
Handicraft and Agriculture	115	7.67
Medium-voltage		
Lighting and Industry		
Peak	320	21.33
Off-peak	112	7.47
Night	80	5.33
Concessions	75	5.00
Concesion Zahle	50	3.33
High tension		
Industry	115	7.67
Kadisha	75	5.00
Cement Sibline	75	5.00

Source: EDL

Annex II. (Chapter 3)

A: Thermal Power plants in the Lebanese power system

Plant	Unit No.	Type	Manufacturer	Operation Year	Installed Net Capacity (MW)	Available Net Capacity in 2004 (MW)	Currently Available Net Capacity (MW) As of January, 2008
Zouk	1	ST	Ansaldo	1984	145	115	100
	2	ST	Ansaldo	1985	145	115	120
	3	ST	Ansaldo	1986	145	130	-
	4	ST	Alstom	1987	172	160	145
	Total Zouk				**607**	**520**	**365**
Jieh	1	ST	Toshiba	1970	65	55	Breakdown not available
	2	ST	Toshiba	1970	65	40	
	3	ST	BBC	1980	72	70	
	4	ST	BBC	1981	72	65	
	5	ST	BBC	1981	72	65	
	Total Jieh				**346**	**295**	**187**
Tyre	1	GT	G.E.	1996	35	35	35
	2	GT	G.E.	1996	35	35	35
	Total Tyre				**70**	**70**	**70**
Ba'albeck	1	GT	G.E.	1996	35	35	35
	2	GT	G.E.	1996	35	35	35
	Total Ba'albeck				**70**	**70**	**70**
Zahrani (CCGT)	1	GT	Ansaldo	1998	145	145	145
	2	GT	Siemens	1998	145	145	145
	3	ST	Ansaldo	2001	145	145	145
	Total Zahrani				**435**	**435**	**435**
Bedawwi (CCGT)	1	GT	Ansaldo	1998	145	145	145
	2	GT	Siemens	1998	145	145	145
	3	ST	Ansaldo	2001	145	145	145
	Total Bedawwi				**435**	**435**	**435**
Total in six power plants					**1,963**	**1,770**	**1,562**

Source: Lebanon Hydrocarbon Strategy Study, 2004; World Bank Analysis, 2007/08.

B. Detailed Calculations on Increasing Supply

Improvement of Dispatch

Costs:

Capital investment:	USD 0
Additional maintenance cost:	USD 0

Benefits:

Savings of 2% on fuel consumption

Fuel consumption 2006	1 028 103 tons FO
	1 118 135 tons Diesel
Fuel saving:	20 360 tons/year FO
	22 360 tons/year Diesel
Value	US$ 7.5 million/year FO at $358/ton
	US$ 16.0 million/year Diesel at 716/ton
IRR: N/A	**Pay back at 12%: Immediate**

Reduction of Technical Losses

Costs:

Capital investment: US$ 200 over five years

Benefits:

Reduction of technical losses by 5% over five years

Additional power delivery by year 5: 351 MWh

Value @ 9.4 Cents/kWh and 80% billing-collection: US$ 26.4 million/year by year 5

IRR: 9% **Pay back at 12%: 15 years**

Rehabilitation of Jieh

Costs:

Capital investment:	USD 100 million over three years
Additional maintenance cost:	USD 10 million/year

Benefits:

Savings of 22.9% on fuel consumption per kWh

Unit No.	Fuel efficiency – Design value (gr/kWh)	Actual value in 2006 (gr/kWh)	Deviation from Design Value
1	250	310	24%
2	250	328	31%
3	240	286	19%
4	240	288	20%
5	240	288	20%
Average	**244**	**300**	**22.9%**

Generation:	1 123 GWh/year
Fuel saving:	77 150 tons/year
Value at $358/ton	US$ 28.4 million/year
Additional capacity:	51 MW
Additional generation at 60% load factor:	268 GWh
Value of additional generation (net of fuel cost):	US$ 11.1 million/year
IRR: 20%	**Pay back at 12%: 5 years**

Rehabilitation of Zouk

Costs:

Capital investment:	USD 100 million over three years
Additional maintenance cost:	USD 10 million/year

Benefits:

Savings of 14.3% on fuel consumption per kWh

Unit No.	Fuel efficiency – Design value (gr/kWh)	Actual value in 2006 (gr/KWh)	Deviation from Design Value
1	224.8	267.4	19%
2	223.3	251.5	13%
3	223.7	-	
4	215.8	241.8	12%
Average	**211.9**	**253.5**	**14.3%**

Generation:	1 830 GWh/year
Fuel saving:	67 293 tons/year
Value at $358/ton	US$24.1 million/year
Additional capacity:	87 MW
Additional generation at 60% load factor:	457 GWh
Value of additional generation (net of fuel cost):	US$ 23.7 million/year
IRR: 27%	**Pay back at 12%: 3 years**

C. New Capacity

Lebanon has four technical options: Medium size Combined Cycle Gas Turbine (300 MW), Large size Combined Cycle Gas Turbine (450 MW), Medium size Steam Turbine (300 MW) and Large size Steam Turbine (500 MW).

Based on the technical characteristics of the plants (see next page) and the assumed fuel prices, the different technologies compare as follows at different load factors:

Levelized total cost of generation (in US ¢ents /kWh at the plant)

	Plant load factor						
	20%	***30%***	***40%***	***50%***	***60%***	***70%***	***80%***
Medium CCGT Gas	12.07	9.53	8.25	7.49	6.98	6.61	6.34
Medium CCGT LNG	15.88	13.33	12.05	11.29	10.78	10.41	10.14
Medium CCGT Diesel	17.69	15.14	13.86	13.10	12.59	12.22	11.95
Large CCGT Gas	11.32	8.97	7.79	7.09	6.62	6.28	6.03
Large CCGT LNG	14.97	12.62	11.44	10.74	10.27	9.93	9.68
Large CCGT Diesel	16.70	14.35	13.18	12.47	12.00	11.67	11.41
Medium Steam Gas	16.39	12.64	10.76	9.63	8.88	8.35	7.94
Medium Steam LNG	20.95	17.20	15.32	14.20	13.45	12.91	12.51
Medium Steam Fuel oil	17.08	13.33	11.45	10.32	9.57	9.04	8.63
Medium Steam Coal	17.74	12.67	10.13	8.61	7.60	6.87	6.33
Large Steam Gas	13.22	10.45	9.06	8.23	7.67	7.28	6.98
Large Steam LNG	17.57	14.79	13.41	12.57	12.02	11.62	11.33
Large Steam Fuel oil	13.88	11.11	9.72	8.89	8.33	7.94	7.64
Large Steam Coal	15.77	11.30	9.07	7.73	6.83	6.19	5.84

The technical characteristics of the plants for each type of fuel are summarized in the table below:

		Medium Combined Cycle 300MW				Large Combined Cycle 450MW				Medium Steam Cycle300MW				Large Steam Cycle 500MW			
		Gas	LNG	Diesel	Fuel Oil	Gas	LNG	Diesel	Fuel Oil	Gas	LNG	Fuel Oil	Coal	Gas	LNG	Fuel Oil	Coal
Installed Capacity	[MW]	**300**	**300**	**300**	**300**	**450**	**450**	**450**	**450**	**300**	**300**	**300**	**300**	**500**	**500**	**500**	**500**
Internal Consumption	[%]	2.0%	0.0	2.0%	2.0%	2.0%	0.0	2.0%	2.0%	5.0%	0.1	5.0%	7.0%	5.0%	0.1	5.0%	7.0%
Net Effective Capacity	[MW]	294.0	294.0	294.0	294.0	441.0	441.0	441.0	441.0	285.0	285.0	285.0	279.0	475.0	475.0	475.0	465.0
Unitary Investment	[US$/kWi	983	983	983	983	918	918	918	918	1264	1264	1264	1685	1264	1264	1264	1544
Total Investment	[MUS$]	295	295	295	295	413	413	413	413	379	379	379	505	632	632	632	772
Energy Generation	[GWh/yea	2188	2188	2188	1334	3282	3282	3282	2002	2121	2121	2121	2076	3411	3411	3411	3340
Plant Load Factor		85%	85%	85%	52%	85%	85%	85%	52%	85%	85%	85%	85%	85%	85%	85%	85%
Heat Rate	[kJ/kWh]	7500	7500	7500	7500	7200	7200	7200	7200	9474	9474	9474	9474	9474	9474	9474	9000
Fuel Variable Cost	[US$/MW	40.17	78.20	134.46	71.63	38.56	75.07	129.09	68.76	48.20	93.84	85.95	22.18	45.90	89.37	81.86	21.07
Plant Life	[years]	30	30.0	30	30	30	30.0	30	30	30	30.0	30	30	30	30.0	30	30

Annex III. (Chapter 4)

A. Key Assumptions

Demand: the assumed annual growth rate of electricity demand to the grid is shown in Table 2 and is detailed in Chapter 2.

Table 2. Demand Growth Rate Assumptions (including elasticities)

Demand Increase	2007	2008	2009	2010	2011	2012	2013	2014	2015
Annual Growth Rate (%)	1.2%	4.1%	5.3%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%

This rate reflects the aggregated growth rate of electricity demand to the grid from all classes of customers (high-voltage, low-voltage, government, concessions, etc.). This annual growth rate of electricity demand differs slightly from the rate used under the RIDPL's analysis as elasticities have been taken into account (see Chapter 2).

Fuel Prices: all fuel prices are variable, using the International Energy Agency's (IEA) crude oil price forecasts as a reference. This crude oil price forecast is also being used by the IMF in its analysis related to Lebanon.

In order to reflect Lebanon's specific contractual terms with oil suppliers, a 3% price premium is applied to the crude oil price. Below are the detailed IEA projections, as well as the associated crude oil prices for Lebanon.

Fuel Cost Forecast		2007	2008	2009	2010	2011	2012	2013*	2014*	2015*
Crude Oil Price (IEA)	US$/barrel	71.3	88.5	83.0	81.0	80.5	80.3	77.0	75.1	73.2
Crude Oil Price for Lebanon	US$/barrel	73.4	91.2	85.5	83.4	82.9	82.7	79.3	77.3	75.3

* arithmetic series calculated based on the prices of the previous 5 years

As far as Diesel and Heavy Fuel Oil with 1% sulfur (HFO 1%) are concerned, their associated prices are indexed to the IEA forecast price of crude oil per barrel.

- **Diesel** is priced based on the above price of crude oil per barrel and an aggregated conversion ratio of 9.36, calculated as detailed in Section C of this Annex.
- **Heavy Fuel Oil 1%** (HFO 1%) is priced based on the above price of crude oil per barrel and an aggregated conversion ratio of 4.81 (see details in Section C of this Annex).

The resulting price projections for these two fuels are presented below.

Fuel Cost Forecast		2007	2008	2009	2010	2011	2012	2013	2014	2015
Crude Oil Price (IEA)	US$/barrel	71.3	88.5	83.0	81.0	80.5	80.3	77.0	75.1	73.2
Diesel	US$/ton	667.4	828.4	776.9	758.2	753.5	751.1	720.3	702.5	684.7
HFO 1%	US$/ton	343.0	425.7	399.2	389.6	387.2	386.0	370.1	361.0	351.9

The price (per barrel) of HFO 1% is inferior to the Crude Oil price since the market for more refined, environmentally-friendly and energy efficient fuels (such as Diesel for example) are in higher demand than heavier fuels, which are in excess supply on the market. As a result, the cost of crude oil is more than recovered by refining companies by the sale price of refined fuels, allowing them to sell heavier fuels at lower price than the Crude Oil price.

Total Fuel Costs: fuel cost projections from 2007 and onwards have been calculated as the total volume (in tons) of HFO 1% and Diesel reportedly consumed in 2006 by EdL (increased to reflect the annual rate of demand growth above), multiplied by the respective fuel prices per ton.

Power Purchase: this is the cost of purchasing power from small local private producers (mostly hydro) and from Syria, using 2006 levels as a baseline and assuming an annual average cost growth rate of 2%.

O&M: this is the cost of works and services as well as transport, using 2006 as a baseline and assuming an annual average cost growth rate of 2%.

Other: these expenses cover Board expenses, various taxes, and general O&M expenses, using 2006 as a baseline and assuming an annual average cost growth rate of 2%.

B. Key Reform Measures Considered

As per the Government's Paris III reform program, also presented in the RIPDL, three main power reform measures are included in the subsidy savings calculations: (i) billing improvement measures; (ii) Beddawi fuel conversion; and (iii) optimization of the transmission and distribution network.

I. Reform Actions Impacting Revenues

Improved billing measures: to measure the impact of improved billing measures, the analysis calculated the savings derived from improvements in billing through the incremental implementation of three theft reduction programs, as proposed by CRA. This brings EdL's 2007 theft level (as % of total supplied electricity) from 17.8% to 8% by 2012. The calculation of billing also factored in the annual growth in demand.

II. Reform Actions Impacting Expenses

Fuel Conversion of Beddawi to Gas: the analysis calculated the savings obtained from switching the Beddawi power plant supply from diesel to Egyptian piped natural gas as of July 1, 2008.

The unit price of piped gas (US$ 5.65/mmbtu) was calculated based on an agreed unit price of US$5.00/mmbtu under the recent agreement with Egypt and an additional US$0.65/mmbtu for transit through Syria. The annual savings from the fuel conversion at Beddawi plant are calculated as the annual reduction in fuel cost.

Transmission and Distribution Network Optimization: the reduction in technical losses, derived from a more efficient electricity dispatch in the electric grid and the associated improved distribution of flows and loads among sub-stations and network lines, and the improvements to the distribution from private management which is under tender by the recruited consulting firm CRA, leads to reduced volume of energy required to meet a given demand. Therefore, the savings from the optimization of EdL's system management and its associated drop in technical losses from 15% in 2006 to 10% by 2012 were calculated as a reduction in annual fuel costs.

III. Other assumptions

Wages: due to the upcoming corporatization and restaffing of EdL, the total cost of EdL's wages was calculated assuming an increase in wage costs as follows: 10%, 10% and 8% in 2008, 2009 and 2010, respectively.

C. *Details of Fuel prices Assumptions*

I. Diesel price

(a) Conversion of Crude Oil price per barrel to Diesel price per barrel

The conversion was calculated as follows: Crude Oil price/bbl X 1.24 = Diesel price/bbl with 1.24 being the average price difference between these two fuel types over the first 10 months of 2007 (using IEA historical prices for crude oil and Mediterranean diesel)

(b) Conversion of Diesel price per barrel to Diesel price per ton

The conversion was calculated as follows: Diesel price/bbl X 7.52 = Diesel price/ton, with 7.52 being the fixed unit conversion factor for Diesel.

(c) The resulting aggregated conversion factor

An aggregated factor of 9.36 reflecting the two consecutive conversions described above was obtained as follows: Crude Oil price/bbl X 1.25 X 7.52 = Crude Oil price/bbl X **9.36** = Diesel price/ton

II. Heavy Fuel Oil 1% Sulfur Content (HFO 1%)

(a) Conversion of Crude Oil price per barrel to HFO 1% price per barrel

The conversion was calculated as follows: Crude Oil price/bbl X 0.72 = HFO 1% price/bbl with 0.72 being the average price difference between these two fuel types over the first 10 months of 2007 (using IEA historical prices for crude oil and Mediterranean HFO 1%)

(b) Conversion of HFO 1% price per barrel to HFO 1% price per ton

The conversion was calculated as follows: HFO 1% price/bbl X 6.67 = HFO 1% price/ton, with 6.67 being the fixed unit conversion factor for HFO 1%.

(c) The resulting aggregated conversion factor

An aggregated factor of 4.81 reflecting the two consecutive conversions described above was obtained as follows: Crude Oil price/bbl X 0.72 X 6.67 = Crude Oil price/bbl X **4.81** = HFO 1% price/ton

D. Debt Service and Investment Plan Assumptions

The data for the debt service projections used in the fiscal analysis are based on figures provided by the Ministry of Finance to the IMF.

The projected capital costs were directly imported from the proposed investment plan, presented in Table 3.7, Chapter 3 (page 44). It was assumed that under the "No Reform" (No Action) scenario, no new investments should be accounted for.

Annex IV (Chapter 5)

Detailed calculation of the cost of public vs. private generation project:

Public:

Public sector

			Efficiency	kJ/kWh	BTU/kWh	BCM/GWh	BCF/GWh	g/kWh(oil equ	g/kWh (LNG)
Large CCGT (450MW)			50%	7200	6825	0.000191	0.006745	172	139
CCGT	MW:		**450**			CM/kWh	CF/kWh		
Gas	Discount		12.0%			0.19109	6.745479		

Costs (USD million)

Year		Capital	Fuel	O&M (V)	O&M(F)	Interest	Repaymen	Dividend	Profit tax	Total	Generation (GWh)	Volume of fuel (Billion Feet3)	Volume of fuel (billion m3)
	0	83	0	0	0	0	0	0	0	83	0	0.0	0.000
	1	248	0	0	0	0	0	0	0	248	0	0.0	0.000
	2	83	0	0	0	27	28	0	0	109	0	0.0	0.000
	3	0	127	13	1	25	28	0	0	166	3,282	22.1	0.627
	4	0	127	13	1	23	28	0	0	164	3,282	22.1	0.627
	5	0	127	13	1	21	28	0	0	162	3,282	22.1	0.627
	6	0	127	13	1	20	28	0	0	160	3,282	22.1	0.627
	7	0	127	13	1	18	28	0	0	159	3,282	22.1	0.627
	8	0	127	13	1	16	28	0	0	157	3,282	22.1	0.627
	9	0	127	13	1	14	28	0	0	155	3,282	22.1	0.627
	10	0	127	13	1	13	28	0	0	153	3,282	22.1	0.627
	11	0	127	13	1	11	28	0	0	151	3,282	22.1	0.627
	12	0	127	13	1	9	28	0	0	150	3,282	22.1	0.627
	13	0	127	13	1	7	28	0	0	148	3,282	22.1	0.627
	14	0	127	13	1	5	28	0	0	146	3,282	22.1	0.627
	15	0	127	13	1	4	28	0	0	144	3,282	22.1	0.627
	16	0	127	13	1	2	28	0	0	142	3,282	22.1	0.627
	17	0	127	13	1	0	0	0	0	141	3,282	22.1	0.627
	18	0	127	13	1	0	0	0	0	141	3,282	22.1	0.627
	19	0	127	13	1	0	0	0	0	141	3,282	22.1	0.627
	20	0	127	13	1	0	0	0	0	141	3,282	22.1	0.627
	21	0	127	13	1	0	0	0	0	141	3,282	22.1	0.627
	22	0	127	13	1	0	0	0	0	141	3,282	22.1	0.627
	23	0	127	13	1	0	0	0	0	141	3,282	22.1	0.627
	24	0	127	13	1	0	0	0	0	141	3,282	22.1	0.627
	25	0	127	13	1	0	0	0	0	141	3,282	22.1	0.627
	26	0	127	13	1	0	0	0	0	141	3,282	22.1	0.627
	27	0	127	13	1	0	0	0	0	141	3,282	22.1	0.627
	28	0	127	13	1	0	0	0	0	141	3,282	22.1	0.627
	29	0	127	13	1	0	0	0	0	141	3,282	22.1	0.627
	30	0	127	13	1	0	0	0	0	141	3,282	22.1	0.627
NPV		$330.17	$719.19	$74.61	$5.68	$97.39	$149.53	$0.00	$0.00	$1,227.03	18,651	125.8	3.564
USCents/kWh		1.77	3.86	0.40	0.03	0.52	0.80	0.00	0.00	6.58			

Gas **Levelized cost USCents/kWh** **6.58**

			$/MBTU				
	-30%	-20%	-10%	Base	10%	20%	30%
Base Gas Price ($/M	3.96	4.52	5.09	5.65	6.22	6.78	7.35
Levelized Cost	5.42	5.81	6.19	6.58	6.96	7.35	7.74

						Base	
Load factor	25%	35%	45%	55%	65%	75%	85%
Levelized Cost	12.16	9.90	8.65	7.85	7.29	6.89	6.58

Private:

Large CCGT (450MW)

CCGT	MW:	**450**
Gas	Discount	12.0%

Costs (USD million)

Year	Capital	Development cost	Working capital/reserve account	Fuel	O&M (V)	O&M(F)	Interest	Repayment	Dividend	Profit tax	Total
0	83	33	0	0	0	0	0	0	0	0	116
1	248	0	0	0	0	0	0	0	0	0	248
2	83	0	35	0	0	0	38	22	0	0	156
3	0	0	0	127	13	1	36	22	29	7	213
4	0	0	0	127	13	1	33	22	29	7	210
5	0	0	0	127	13	1	31	22	29	7	208
6	0	0	0	127	13	1	28	22	29	7	205
7	0	0	0	127	13	1	26	22	29	7	202
8	0	0	0	127	13	1	23	22	29	7	200
9	0	0	0	127	13	1	21	22	29	7	197
10	0	0	0	127	13	1	18	22	29	7	195
11	0	0	0	127	13	1	15	22	29	7	192
12	0	0	0	127	13	1	13	22	29	7	190
13	0	0	0	127	13	1	10	22	29	7	187
14	0	0	0	127	13	1	8	22	29	7	184
15	0	0	0	127	13	1	5	22	29	7	182
16	0	0	0	127	13	1	3	22	29	7	179
17	0	0	0	127	13	1	0	0	29	7	177
18	0	0	0	127	13	1	0	0	29	7	177
19	0	0	0	127	13	1	0	0	29	7	177
20	0	0	0	127	13	1	0	0	29	7	177
21	0	0	0	127	13	1	0	0	29	7	177
22	0	0	0	127	13	1	0	0	29	7	177
23	0	0	0	127	13	1	0	0	29	7	177
24	0	0	0	127	13	1	0	0	29	7	177
25	0	0	0	127	13	1	0	0	29	7	177
26	0	0	0	127	13	1	0	0	29	7	177
27	0	0	0	127	13	1	0	0	29	7	177
28	0	0	0	127	13	1	0	0	29	7	177
29	0	0	0	127	13	1	0	0	29	7	177
30	0	0	-35	127	13	1	0		29	7	142
	$330.17	$29.51	$23.98	$719.19	$74.61	$5.68	$139.43	$121.96	$164.12	$41.03	$1,527.72
	2.90	0.26	0.21	6.32	0.66	0.05	1.23	1.07	1.44	0.36	13.43

Taxes

Tax on fuel	0%
Tax on O&M	0%
Tax on imported equipment	0%
Profit tax rate	20%

Levelized cost (USCents/kWh) **8.19**

Financing terms

Debt/equity	2.33333333	Equity	144
Interest on senior debt	11%	Loan Amount	337
Maturity senior debt	15		
Targetted return/equity	20%		

Gas Cost	4.12	4.58	5.09	5.65	6.22	6.84	7.52
Levelized C	11.56	12.07	12.64	8.19	13.91	15.01	15.37

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